Comment Report

Project Name:	2021-01 Modifications to MOD-025 and PRC-019 | Draft 1
Comment Period Start Date:	9/29/2022
Comment Period End Date:	11/17/2022
Associated Ballots:	2021-01 Modifications to MOD-025 and PRC-019 MOD-025-3 Implementation Plan IN 1 OT 2021-01 Modifications to MOD-025 and PRC-019 MOD-025-3 IN 1 ST 2021-01 Modifications to MOD-025 and PRC-019 PRC-019-3 Implementation Plan IN 1 OT 2021-01 Modifications to MOD-025 and PRC-019 PRC-019-3 IN 1 ST

There were 78 sets of responses, including comments from approximately 188 different people from approximately 125 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree the language proposed in MOD-025-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree the language proposed in MOD-025-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Do you agree the language proposed in MOD-025-3 Requirement R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you agree the language proposed in MOD-025-3 Requirement R4? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you agree the language proposed in MOD-025-3 Attachments 1, 2, and 3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. The SDT believes the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The SDT proposes a 1-year implementation plan for MOD-025-3 Requirements R3 and R4, with an additional 2 years (3 years total) for compliance with Requirements R1 and R2. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

8. Provide any additional comments on MOD-025-3 and technical rationale document for the standard drafting team to consider, if desired.

9. Do you agree the language proposed in PRC-019-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

10. Do you agree the language proposed in PRC-019-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

11. Do you agree the language proposed in PRC-019-3 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

12. The SDT believes the language of PRC-019-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

13. The SDT proposes a 1-year implementation plan for PRC-019-3 Requirement R2. For Requirement R1 with reoccurring periodicity for existing Facilities, the Implementation Plan proposes a six year reoccurring periodicity from the date of previous coordination date of PRC-019-2 R1. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period.

14. Provide any additional comments on PRC-019-3 and technical rationale document for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Santee Cooper	Chris Wagner	1		Santee Cooper	Anthony Noisette	Santee Cooper	1,3,5,6	SERC
					LaChelle Brooks	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC
					Daniel Mason	Portland General Electric Co	6	WECC
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC

					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
Lincoln Electric System	Eric Ruskamp	1,3,5,6		LES	Eric Ruskamp	Lincoln Electric System	6	MRO
					Dan Pudenz	Lincoln Electric System	1	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Scott Berry	Wabash Valley Power Association	3	RF

					Jason Procuniar	Buckeye Power, Inc	4	RF
					Chandler Brown	Sunflower Electric Power Corporation	1	MRO
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
ISO New England, Inc.	Kathleen Goodman	2	NA - Not Applicable,NPCC	Standards Review Committee (SRC)	Helen Lainis	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Mike Del Viscio	PJM	2	RF
					Ali Miremadi	CAISO	2	WECC
					Charles Yeung	SPP	2	MRO
					Andrew Gallo	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Andrew Gallow	ERCOT	2	Texas RE
MRO	Kendra Buesgens	1,2,3,4,5,6,7	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO

					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC

					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
Dan Kopin	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
John Pearson	ISO New England, Inc.	2	NPCC
Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Michael Jones	National Grid	3	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Glen Smith	Entergy Services	4	NPCC

					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC

					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree the language proposed in MOD-025-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Decreasing the submittal window from 90 calendar days down to 30 days could be problematic, especially given that the testing is done on a seasonal basis. The testing window is already very narrow, and making it even more condensed could prove even more difficult. AEP sees no justification-for. nor reliability benefit-in, reducing the window for submittal by such a considerable amount.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy seeks clarification on devices to include FACTs and justification on the need for testing of these. SVCs and other FACTS devices we view as not having moving parts which should limit their change in output and response over time and we seek clarification of their inclusion.

Also, the proposed MOD-025 revision transforms what was formerly a "required testing verification of demonstrated capability" into some form of an engineering analysis justifying a theoretical capability curve. The standard needs to include a better definition of "Engineering review" or "engineering analysis" along with examples or prescribed methods of how this "engineering analysis" is to be conducted.

In addition, FirstEnergy does not understand how the proposed revision to MOD-025 for reactive testing will provide any additional or more accurate information to the transmission planning entities since we currently already submit most of the needed information.

Generator capability curves are submitted via the annual MOD-032 submittals to PJM. Analysis of over/under excitation limiters are already included in the required PRC-019 documentation.

The excerpt below comes from the summary section of the NERC white paper "Implementation of NERC Standard MOD-025-2"

"The PPMVTF believes that there is value in performing the staged verification tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing may not be directly usable to represent the actual capability of the machine in power system models, and that the tests do not generally accomplish the stated purpose of the standard.

Likes 0	

Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment

1) MOD-025-3 aims to verify but not to develop the real and reactive power capability for BES Facilities. Developing the real and reactive power capability D-curve has been covered in other standards such as PRC-019. Therefore, it is suggested to keep only staged testing data and/or operational data for capability verification. It is also suggested that any requirments that are related to capability development in the BES Facility Capability Report should be removed, for example, composite capability curve and associated PQ data table, documentation showing the engineering basis and verification methodology.

2) We agree that the current verification process may not be adequate when the data points obtained from a staged test or operational data might not duplicate the facility thermal capability curve (D-curve). Having said that we think that the added R3 and R4 requirements are the right way to address these issues. The new R3 requirement provides the needed feedback mechanism to address Transmission Planner concerns regradings any technical issues that it identifies with the Real or Reactive Power capability information. It should be left up to the Transmission Planner to communicate to the generation and transmission owners the required information required to address their concerns. The most efficient way to address the model accuracy issues is to encourage dialogue between entities to ensure that verifications are accurate and appropriate for the needs of the Transmission Planner.

3) The verification process should be simplified and adding more description to the process may not translate to more accuracy in the modeling.

4) Some of the proposed required verifying documentation is irrelevant or/and covered in other NERC standards such as the manufacturer-supplied thermal capability curve (D-curve) for the old plant (some of these facility has been updated/modified such as rating changes due to winding update, or excitation and governor/turbine change), the development of facility D-cure (instead of verification it), the limiters (that has been provided as part of PRC-019). As stated I think the level of detailed additional information that is needed should be left to the planners depending on the quality of the submitted data to address any modeling issues.

5) Should each and every unit of the same sister units be tested in the same power plant?

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	No
Document Name	

Comment

The proposed timeline of 30-day submittal after verification date may not be sufficient time due to internal review and approval processes. Therefore, LADWP recommends the timeline of 60 days would be appropriate.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

“Composite capability curve and associated PQ data table,” in R1.3.2 should be deleted, since we do not expect that this information will be put to any useful purpose. The TPs we deal with refuse to accept anything but as-measured data. We have been told when attempting to provide MOD-025-2 Note 2 corrections (similar to what must be provided for MOD-025-3) that their reactive capability criteria are market rules issued under their authority as ISOs, so deviations from NERC standards don’t matter.

MOD-025-3 as presently written does not address this situation, despite the fact that TPs will now be applicable entities (they aren’t for MOD-025-2), and correction calculations must be performed instead of being optional. TPs can send no-concerns notifications for R3 of MOD-025-3, then as ISOs throw away the engineering analyses (as they do now for our attempts at Note 2 corrections) and use solely as-measured data.

There should be no changes to MOD-025 unless the great majority of TPs agree that in their they will use in their planning the corrections provided under Rev. 3 of this standard. This requires however overcoming their objections that calculations for tests that were limited by operating conditions represent predictions and not demonstrated capabilities.

We are not adverse to doing the work needed for BES reliability, but MOD-025-3 has the appearance of being a product without customers. The SDT has advised that MOD-025-3 may at least spark discussion of the issues at hand, but this is inadequate justification for the substantial GO effort and expenditures that the proposed standard will require.

We also suggest that the proposed R1.3 language be modified to allow six months after the test date, where tests are the MOD-025-3 compliance method selected, and that greater clarity be provided regarding evidence criteria for the engineering basis, verification methodology and applicable data of R1.3.3. Are screen shots of voltage drop calculations sufficient?

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
The SERC Generator Working Group suggest 60 days instead of 30 days. 30 days is usually not enough time due to the involvement of a 3rd party.	

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the changes made regarding the staged verification of testing and the required supporting materials for Requirement R1.

PG&E supports the EEI input for Q1 on their listed changes and clarifications for Requirement R1 and its sub-parts.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

MOD-025-3 does not address the fundamental concern of inaccurate model data. The verification described does not appear to provide usable data to Transmission Planners for modeling purposes and it is unclear what the data should be used for.

Pmax, Pmin, Qmax, and Qmin results are not adequate to be used in the models for the following reasons:

o Test results must be corrected for various factors (weather, temperature, etc.) in order to compare or translate into the model. Transmission Planners may not be capable of performing or understanding corrections and the corrections are not going to be perfect. Validating Pmax, Pmin, Qmax, and Qmin given these corrections provides only a ballpark comparison with potentially significant accuracy issues.

o Test results are dependent on the current grid state, and are not adequate for comparison as written in MOD-025-3.

o Testing does not test the limits of the inverters or turbines themselves because it may stop at 0.95 PF or Power Plant Controller limits. If inverters or turbines are down, others may be able to compensate for their lack of output – however, this testing will not capture limits on inverters/turbines themselves that may have been incorrectly programmed. As this reads as more of a performance test standard, this is a performance issue that would not be tested.

o   Transmission Planners will receive varying documentation on how testing was performed and are not equipped technically to adequately review testing material.

Other concerns:

Please clarify the following types of test situations.

o   “For individual devices or generators greater than 20 MVA (gross nameplate rating) perform verification on an individual basis” – Example: An IBR with multiple phases, some phases are <20 MVA while others are greater than 20 MVA. The plant aggregates to greater than 75 MVA. Would each phase be considered a “generator” – therefore, the <20 MVA phases can be tested in aggregate with the entire site? Then the phases that are greater than 20 MVA must be tested separately?

Section 3 – “The AVR equipment is in automatic voltage regulating mode.”

o   Some legacy plants are operating in Power Factor mode and this phrase seems like directing the plant to switch from PF mode to voltage control mode for testing. Consider adding a note to address testing PF mode plants.

{C}·   Section 3 – “All aux equipment in service for normal operation.” Recommend the SDT to consider how this may impact testing. For example, capacitors switching in during testing will back the inverters/turbines off from providing support. If the intention of the requirement is to find the true limits of inverters or turbines, it may be advantageous to consider testing without aux equipment in normal operation.

{C}o   A little background: in PJM, D-curve testing (very similar to MOD-025 testing) requires that entities do not have capacitors in normal operating mode. AES Clean Energy had to perform separate testing as a result. This type of testing is common and seems duplicative for owners.

{C}·   30 days is an insufficient amount of time to assemble and submit Attachment 2, especially for aggregate plants where testing will be performed at once on multiple units, and where additional information must now be assembled/provided.

{C}·   180 days following a change that affects output power is not a sufficient amount of time to analyze a change and perform testing.

Recommendations:

o   The SDT should consider how the data collected in MOD-025-3 can be used to address modeling inaccuracies. Please provide guidance on how Transmission Planners or Generator Owners can use results in comparison with a model. In our point of view, the data is not comparable and cannot be used for modeling.

o   The SDT should consider providing additional guidance on how the data collected in MOD-025-3 can and should be used by the Transmission Planner and how the Transmission Planner shall review results. Along with this recommendation, the SDT should consider if this testing is necessary.

o   If the data is used for a modeling comparison, it is more sensible for testing to occur based on what is modelled rather than 20 MVA. The language in Section II of Attachment 1 vaguely says “consider applicable modeling expectations of the TP” and this may be contradicted by the 20 MVA individual unit requirement.

o   Consider if MOD is the appropriate standard for this testing.

o   Update 30 calendar days to submit Attachment 2 to 180 calendar days as more information is now required to be provided.

o   Consider changing the timeline after a change from 180 days to 6 calendar months.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The purpose of MOD-025-3 is "to ensure accurate information on BES Facilities Real and Reactive Power capability is available for planning models used to assess BES reliability." The intent of MOD-025-3 from reliability standpoint does make sense, however, in practice results are rarely actuals, but derived approximates for Pmax, Pmin, Qmax and Qmin.

• MOD-025 is a snapshot of current unstressed conditions and rarely shows the actual Real and Reactive capability as designed, especially for inverter-based resources (IBR) BES Facilities which require 90% or greater of units to be on-line.

• An entity can request the Reliability Coordinator (RC) or Transmission Operator (TOP) to adjust the voltage on the transmission system, but this is problematic, only possible if other Reactive Power resources are available in the area and adjusting the transmission system for the purposes of testing may lead to instability unnecessarily. Further, the RC/TOP may have to adjust the transmission system voltage multiple times for all applicable entities to complete testing.

• If the electric grid were actually stressed, all power plant testing would be cancelled.

• The MRO NSRF recommends the addition of a Transmission Planner (TP) exemption where the TP doesn't see value in the MOD-025 data.

The MRO NSRF does not agree with the reductions in the verification testing timeframe for situations where the resource owner discovers a change that affects a resource's Real Power or Reactive Power capability (see Section I, Item 4). In these cases, an entity should continue to have 12 months to analyze the issue and conduct the required testing.

MOD-025-3 is administratively burdensome with 30-day, 90-day, 180-day, 10-year and 180-day 10% change requirements which must all be tracked and verified. Consolidating reporting to 12 months eases this administrative burden.

"Facility" by itself is ambiguous, unclear and should be clarified according to NERC SDT writing rules. "Facility" could be either the individual generating resource or the entire BES plant. Therefore an auditor could require MOD-025 tests for all 1 MVA individual wind turbines or solar inverters at a given BES plant. The SDT needs to clarify the intent for Attachment 1, Section II, and item #2. The SDT should remove the word "each" from Measures 1 and 2. The SDT should consider the use the terms such as "BES plant" meaning:

• Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or

• Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Related to Attachment 1, Section II, 2., if an applicable entity is expected to test “considering applicable modeling expectations of the respective Transmission Planner.”, then their must be a requirement for the TP to publish applicable modeling expectations for MOD-025 testing.

The MRO NSRF would request that the SDT clearly define all trends in Attachment 2, Figure 1 and 2 capability curves.

Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.

The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.

R1.3 would be better stated: “Submit the Real Power and Reactive Power verification to the associated Transmission Planner in accordance with Attachment 2.”

Sections R1.3.1, R1.3.2, and R1.3.3 should be eliminated in order to maintain consistency with 1.1 and 1.2 referring to the attachment instead of re-stating what is in the attachment. This would avoid potential conflicts and confusion (which already appear to exist as currently drafted).

M1 could also be cleaned up to state: “Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each applicable facility and submitted the information to the associated Transmission Planner in accordance with Requirement R1.”

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS generally supports the changes made to Requirement 1, but agrees with the following comments submitted by EEI on behalf of their memebers:

a) Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.

b) The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.

c) Clarify Attachment 1, Section II part 2 as to whether this specification is intended to align with the BES definition Inclusion I2, I4 or both. We additionally ask for clarity for the statement, “For individual devices or generators 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, **perform verification on an individual unit basis or in the aggregate**, considering applicable modeling expectations of the respective Transmission Planner.” The bold face text seems to imply that an entity might be required to test individual resources under BES Inclusion I4. If this is the intent, we do not support such a requirement. Testing I4 resources individually would add a significant amount of time for testing with no reliability purpose. In addition, I4 resources are designed to operate as an aggregated block not as individual resources.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree with the shortened time period for submittal to Transmission Planner from 90 to 30 calendar days. External vendors are routinely hired to perform the testing for the Generator Owner and a 30 day window does not provide enough time to receive the report from the vendor and then perform the necessary internal reviews to ensure accuracy. In addition, many Transmission Planners still use their own version of a spreadsheet/form to gather the test data in lieu of the MOD-025 Attachment and typically allow for a longer submittal window that was is currently being proposed. Constellation requests that obligation on what form to provide modeling data, and the submission timeline be decided by each applicable Transmission Planner and not prescribed by the NERC Standard or be reverted back to the current 90-day submission window. There is also some confusion on what is intended by the “verification date” as it does not appear to be the same as the test date. Constellation requests that R1.3 language be modified to state “after the verification date as defined in Attachment 1, Step 1”. The proposed language is now requesting “one per unit voltage” calculation without any supporting methodology. This is not feasible for typical testing conditions as most synchronous generating units will need to increase voltage to 1.05 per unit in lagging and 0.95 per unit leading during operational testing to be able to produce the necessary VARs. Constellation requests the SDT provide additional guidance on how the “one per unit voltage” is intended to be used. Constellation also requests that the SDT evaluate the implications of on-line test data not matching the engineering analysis. This mismatch could occur due to ambient temperature of air-cooled machines, system limitations, sister unit var output if online during the test, river flow for hydro generating units, generator terminal voltage limits, etc. This mismatch of data could potentially cause the Transmission Planner to reject the test results of a generating unit and therefore require the Generator Owner to re-perform the test.

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation does not agree with the shortened time period for submittal to Transmission Planner from 90 to 30 calendar days. External vendors are routinely hired to perform the testing for the Generator Owner and a 30 day window does not provide enough time to receive the report from the vendor and then perform the necessary internal reviews to ensure accuracy. In addition, many Transmission Planners still use their own version of a spreadsheet/form to gather the test data in lieu of the MOD-025 Attachment and typically allow for a longer submittal window that was is currently being proposed. Constellation requests that obligation on what form to provide modeling data, and the submission timeline be decided by each applicable Transmission Planner and not prescribed by the NERC Standard or be reverted back to the current 90-day submission window.

There is also some confusion on what is intended by the "verification date" as it does not appear to be the same as the test date. Constellation requests that R1.3 language be modified to state "after the verification date as defined in Attachment 1, Step 1".

The proposed language is now requesting "one per unit voltage" calculation without any supporting methodology. This is not feasible for typical testing conditions as most synchronous generating units will need to increase voltage to 1.05 per unit in lagging and 0.95 per unit leading during operational testing to be able to produce the necessary VARs. Constellation requests the SDT provide additional guidance on how the "one per unit voltage" is intended to be used.

Constellation also requests that the SDT evaluate the implications of on-line test data not matching the engineering analysis. This mismatch could occur due to ambient temperature of air-cooled machines, system limitations, sister unit var output if online during the test, river flow for hydro generating units, generator terminal voltage limits, etc. This mismatch of data could potentially cause the Transmission Planner to reject the test results of a generating unit and therefore require the Generator Owner to re-perform the test.

Alison Mackellar on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	

Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	

Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Do not agree with changing the 90-day timeframe to 30 days. Also, in previous revisions to standards the Requirement number, if being replaced, would be labeled as "Reserved" instead of combined into a single requirement in order to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The 30 day submittal window is too short and should remain 90 calendar days.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Verification of reactive power capability as defined in attachment 1 is not well defined. Several previous tests were not able to accomplish documented limits due to system conditions. Overall, in our opinion, there is not much value to performing this particular test.	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
Requiring entities to use what could be only a paperwork review to check capability is not going to show limitations that might be occurring. Actual performance tests or recorded operational data should be allowed as other means to demonstrate verification. Requirement R1 refers to the verification described in Attachment 1. To allow the use of actual performance data, modify the language in Attachment 1, Section II as follows: 2. For individual devices or generators 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, perform verification on an individual unit basis or in the aggregate, considering applicable modeling expectations of the	

respective Transmission Planner. The verification shall use testing or operational data as part of the engineering analysis to provide real and reactive power capability data for planning models

In addition, rather than repeating all of the inclusion criteria for BES units, the SRC requests the SDT clarify why the Applicability section cannot be clarified to indicate the standard is applicable to all BES units..

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES

Answer	No
Document Name	

Comment

We are generally supportative of the changes being proposed to these standards, however there are a few issues that lead to ultimate casting of a negative ballot.

The purpose of MOD-025-3 is “to ensure accurate information on BES Facilities Real and Reactive Power capability is available for planning models used to assess BES reliability.” The intent of MOD-025-3 from reliability standpoint does make sense, however, in practice results are rarely actuals, but derived approximates for Pmax, Pmin, Qmax and Qmin.

• MOD-025 is a snapshot of current unstressed conditions and rarely shows the actual Real and Reactive capability as designed

• An entity can request the Reliability Coordinator (RC) or Transmission Operator (TOP) to adjust the voltage on the transmission system, but this is problematic, only possible if other Reactive Power resources are available in the area and adjusting the transmission system for the purposes of testing may lead to instability unnecessarily. Further, the RC/TOP may have to adjust the transmission system voltage multiple times for all applicable entities to complete testing.

• If the electric grid were actually stressed, all power plant testing would be cancelled.

• The MRO NSRF recommends the addition of a Transmission Planner (TP) exemption where the TP doesn’t see value in the MOD-025 data.

The MRO NSRF does not agree with the reductions in the verification testing timeframe for situations where the resource owner discovers a change that affects a resource’s Real Power or Reactive Power capability (see Section I, Item 4). In these cases, an entity should continue to have 12 months to analyze the issue and conduct the required testing. However, 180 days is an acceptable timeframe for normal periodic verification testing, new applicable Facilities and Facilities that are returning to service after a planned or unplanned outage of 180 days or more and overlaps it scheduled verification date or has not been verified within the past 10 years. Further, MOD-025-3 is administratively burdensome with 30-day, 90-day, 180-day, 10-year and 180-day 10% change requirements. All of which must be tracked and verified.

“Facility” by itself is ambiguous, unclear and should be clarified according to NERC SDT writing rules. “Facility” could be either the individual generating resource or the entire BES plant. Therefore an auditor could require MOD-025 tests for all 1 MVA individual wind turbines or solar inverters at a given BES plant. The SDT needs to clarify the intent for Attachment 1, Section II, and item #2. The SDT should remove the word “each” from Measures 1 and 2. The SDT should consider the use the terms such as “BES plant” meaning:

• Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or

• Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Related to Attachment 1, Section II, 2., if an applicable entity is expected to test “considering applicable modeling expectations of the respective Transmission Planner.”, then their must be a requirement for the TP to publish applicable modeling expectations for MOD-025 testing.

The MRO NSRF would request that the SDT clearly define all trends in Attachment 2, Figure 1 and 2 capability curves.

Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.

The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

The proposed time line of 30 calendar days after the verification date is not a sufficient amount of time. Tri-State recommends a timeline of 60 calendar days after the verification date.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	No
Document Name	

Comment

SMUD agrees with the general language of MOD-025-3 Requirement 1 but strongly feels that the Standards Drafting Team consider extending the time for the Generator Operator (GO) to submit information to the Transmission Planner (TP) to 60 calendar days. For situations where the GO hires a consultant to perform the verification work, 30 calendar days may not be enough time for the GO to finalize the work with the consultant, and then submit all required information to the TP.

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Submitting the completed Attachment 2 documentation and data to the Transmission Planner within 30 days is not enough time for all the required peer reviews and Engineering analysis.

We recommend changing the requirement to say “Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 180 calendar days after the verification date.” The additional 150 days will allow time for a proper Engineering Analysis and Peer review and have a positive impact on the reliability of the planning model.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Details of the submission to TP should be in Att. 2 (since used) and does not need to be listed under R1.3 too.

Southern Company recommends the addition of a Transmission Planner (TP) exemption where the TP doesn’t see value in the MOD-025 data.

In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group.

In addition to these comments, Southern Company supports the comments submitted by the NAGF.

In addition to these comments, Southern Company supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Requirement R1 requires reporting within 30 days then refers to Attachment 1. Attachment 1 states that the date of verification is when the report is completed. There does not appear to be any specified time between the date of the actual verification testing and completing the report, leaving this open ended. Tacoma Power recommends revising Requirement R1 to include the language in Attachment 1, rather than referencing it.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

SDT should consider:

1 - Adding language to exempt R1 requirements if Transmission Planning does not utilize R1 data.

2 - Identifying expectations for modeling a Pumped-Storage unit for both Pump and Electrical Generator..

3 - Collocating Figure 2: Example Composite Capability Curve for IBR Facility with Figure 1 and Section III; provided PQ curve data table associated with Figure 1.X composite capability curve as well as additional legend assigned.

4 - Common interpretation for MOD-025 verification requirements vary. Recommend that the Drafting Team add clarity if multiple verification requirements exist for Facilities which operator in multiple modes, e.g. BESS, pumped storage generation, dual-fuel, etc.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Agreement with the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Buckeye Power, Inc. - 5 - RF

Answer	No
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES Power Marketing.

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment

MOD-025-3 similar to all MOD-025 standards remains fundamentally flawed and incapable of meeting to original intent.

PacifiCorp submits standards MOD-026, MOD-027, MOD-032 and MOD-033 as superior alternatives to keeping MOD-025. These standards already require event performance analysis that should capture actual plant performance. Entities already submit plant performance data.

PacifiCorp asks NERC to request FERC to retire MOD-025 or justify the actual reliability value of MOD-025.

The original intent for MOD-025 was to provide real and reactive power data to be used in NERC models. The intent was nice in theory but reality has demonstrated MOD-025 as administrative and of little value in terms of reliability.

· MOD-025 is a snapshot of current unstressed conditions and therefore almost never shows the true real and reactive capability as designed.

· If the electric grid were actually stressed, all power plant testing would be cancelled.

· MOD-025 is administratively burdensome with 30-day, 90-day, 180-day, 10-year and 180-day 10% change requirements. All of which must be tracked and verified.

The new proposed MOD-025-3 standard appears to violate the existing NERC Bulk Electric System definition in Attachment 1, section II and item 2, by dropping below the BES definition by requiring testing of individual wind turbines / solar inverters creating an unfair and unjust requirement which violates FERC's own fundamental fair and just law making principals. As an example:

· A non-NERC registered entity with units installed at 69 kV and rated up to 74 MVA have no NERC jurisdiction and therefore no risk or obligations for mandatory zero defect standards with $1,000,000 and higher per day penalties.

· A NERC registered entity with a single BES unit and one or more non-BES units connected at 69 kV and rated up to 74 MVA has a significant administrative burden and the risk of zero-defect standard violations.

· This is fundamentally unfair and unjust which violates FERC principals.

· Language that exceeds the NERC BES definition should be removed or revised to match the current NERC BES definition.

The SDT should remove the work "each" from Measures 1 and 2 as fundamentally wrong. The SDT should consider the use the terms such as "BES plant" meaning:

· Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater

· Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

While EEI supports the changes made regarding the staged verification testing and the required supporting materials, the following changes and clarifications are needed to Requirement R1 and its subparts:

1. Delete "of its applicable Facilities" from subparts 1.1 and 1.2 because this is already stated in Requirement 1.
2. Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.
3. The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.
4. Provide clarity on the meaning of the term "verification date" used in subpart 1.3.
5. Clarify the meaning of the term "each Facility" as used in Measure M1. While entities are obligated only to provide verification of Real and Reactive Power capability for resources as identified in the Applicability Section and in accordance with the BES definition; the use of "each Facility" seems to imply something different. To address this concern, consideration should be given to using the term "applicable Facilities" rather than "each Facility".
6. Clarify Attachment 1, Section II, part 1 aligning this specification to the BES definition Inclusion I2.
7. Clarify Attachment 1, Section II part 2 as to whether this specification is intended to align with the BES definition Inclusion I2, I4 or both. We additionally ask for clarity for the statement, "For individual devices or generators 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, **perform verification on an individual unit basis or in the aggregate**, considering applicable modeling expectations of the respective Transmission Planner." The bold face text seems to imply that an entity might be required to test individual resources under BES Inclusion I4. If this is the intent, we do not support such a requirement. Testing I4 resources individually would add a significant amount of time for testing with no reliability purpose. In addition, I4 resources are designed to operate as an aggregated block not as individual resources.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment
Black Hills Coproration (BHP) agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

The NAGF requested that the proposed R1.3 language be modified to state “after the verification date as defined in Attachment 1, Step 1”. The NAGF supports the current 90-day window after the verification date for GOs to provide R1.3 information to the Transmission Planner.

Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.

Answer	No
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI.

Additonally, PGE requests clarification about how Attachment 1 is establishing the verification date. Attachment 1 appears to establish a date for each verification, irrespecitive of verification test that might be event triggered between the 10-year periodic interval. PGE believes the Standard needs to be clearer that the 10-year verification interval from the last verification performed.

Likes 0	
Dislikes 0	
Response	

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	
Comment	

The purpose of MOD-025-3 is “to ensure accurate information on BES Facilities Real and Reactive Power capability is available for planning models used to assess BES reliability.” The intent of MOD-025-3 from reliability standpoint does make sense, however, in practice results are rarely actuals, but derived approximates for Pmax, Pmin, Qmax and Qmin.

{C}· MOD-025 is a snapshot of current unstressed conditions and rarely shows the actual Real and Reactive capability as designed, especially for inverter-based resources (IBR) BES Facilities which require 90% or greater of units to be on-line.

{C}· An entity can request the Reliability Coordinator (RC) or Transmission Operator (TOP) to adjust the voltage on the transmission system, but this is problematic, only possible if other Reactive Power resources are available in the area and adjusting the transmission system for the purposes of testing may lead to instability unnecessarily. Further, the RC/TOP may have to adjust the transmission system voltage multiple times for all applicable entities to complete testing.

{C}· If the electric grid were actually stressed, all power plant testing would be cancelled.

{C}· The MRO NSRF recommends the addition of a Transmission Planner (TP) exemption where the TP doesn't see value in the MOD-025 data.

The MRO NSRF does not agree with the reductions in the verification testing timeframe for situations where the resource owner discovers a change that affects a resource's Real Power or Reactive Power capability (see Section I, Item 4). In these cases, an entity should continue to have 12 months to analyze the issue and conduct the required testing.

MOD-025-3 is administratively burdensome with 30-day, 90-day, 180-day, 10-year and 180-day 10% change requirements which must all be tracked and verified. Consolidating reporting to 12 months eases this administrative burden.

"Facility" by itself is ambiguous, unclear and should be clarified according to NERC SDT writing rules. "Facility" could be either the individual generating resource or the entire BES plant. Therefore an auditor could require MOD-025 tests for all 1 MVA individual wind turbines or solar inverters at a given BES plant. The SDT needs to clarify the intent for Attachment 1, Section II, and item #2.

The SDT should remove the word "each" from Measures 1 and 2. The SDT should consider the use the terms such as "BES plant" meaning:

- Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or
- Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Related to Attachment 1, Section II, 2., if an applicable entity is expected to test "considering applicable modeling expectations of the respective Transmission Planner.", then their must be a requirement for the TP to publish applicable modeling expectations for MOD-025 testing.

The MRO NSRF would request that the SDT clearly define all trends in Attachment 2, Figure 1 and 2 capability curves.

Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.

The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.

R1.3 would be better stated: “Submit the Real Power and Reactive Power verification to the associated Transmission Planner in accordance with Attachment 2.”

Sections R1.3.1, R1.3.2, and R1.3.3 should be eliminated in order to maintain consistency with 1.1 and 1.2 referring to the attachment instead of re-stating what is in the attachment. This would avoid potential conflicts and confusion (which already appear to exist as currently drafted).

M1 could also be cleaned up to state: “Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each applicable facility and submitted the information to the associated Transmission Planner in accordance with Requirement R1.”

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

In R1, Part 1.3, we believe the time allowed to submit the required information to the Transmission Planner should be “within 90 calendar days after the verification date” rather than 30 calendar days. This is consistent with MOD-025-2 (R1/Part 1.2 and R2/Part 2.2) and allows the Generator Owners that have been subject to MOD-025-2 to maintain procedural / controls practices related to this timing requirement in place. For verifications that can occur up to ten years apart (for an existing applicable Facility), the “urgency” of providing the verified information to the Transmision Planner within 30 calendar days vs. 90 calendar days seems unwarranted.

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

Sections R1.3.1, R1.3.2, and R1.3.3 should be eliminated in order to maintain consistency with 1.1 and 1.2 referring to the attachment instead of re-stating what is in the attachment.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

30 calendars day report to the Transission Planner is not enough time and creates additional tracking burden. Recommend removing the requirement to report data within a certain time after the verification, and change the requirement so that the reporting is included in the periodicity of the testing. For example, with a 10 calendar year periodicity, the verification and reporting would be required within 10 calendar years. The next period for verification would start at the verification date, not the reporting date.

There should be an opt-out for R1 so that if the Transmission Planner is not using this verification, the Generator owner doesn't need to repeat the verification.

R1 and R2 are exactly the same except R1 is for Generator Owners and R2 is for Transmission Owners. Couldn't they be a single requirement for both Generator and Transmission Owners?

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

MOD-025 in its entirety should be retired. It is not useful and is not cost effective. Allowing only 30-day after testing to get final reports to TO is unreasonable, 90-days is sufficient.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No

Document Name	
Comment	
1. MOD-025 in its entirety should be retired. It is not useful and is not cost effective. Allowing only 30-day after testing to get final reports to TO is unreasonable, 90-days is sufficient.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	No
Document Name	
Comment	
MOD-025 in its entirety should be retired. It is not useful and is not cost effective. Allowing only 30-day after testing to get final reports to TO is unreasonable, 90-days is sufficient.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The purpose of MOD-025-3 is “to ensure accurate information on BES Facilities Real and Reactive Power capability is available for planning models used to assess BES reliability.” The intent of MOD-025-3 from reliability standpoint does make sense, however, in practice results are rarely actuals, but derived approximates for Pmax, Pmin, Qmax and Qmin.

MOD-025 is a snapshot of current unstressed conditions and rarely shows the actual Real and Reactive capability as designed, especially for inverter-based resources (IBR) BES Facilities which require 90% or greater of units to be on-line.

An entity can request the Reliability Coordinator (RC) or Transmission Operator (TOP) to adjust the voltage on the transmission system, but this is problematic, only possible if other Reactive Power resources are available in the area and adjusting the transmission system for the purposes of testing may lead to instability unnecessarily. Further, the RC/TOP may have to adjust the transmission system voltage multiple times for all applicable entities to complete testing.

If the electric grid were actually stressed, all power plant testing would be cancelled.

NVE recommends the addition of a Transmission Planner (TP) exemption where the TP doesn't see value in the MOD-025 data.

NVE does not agree with the reductions in the verification testing timeframe for situations where the resource owner discovers a change that affects a resource's Real Power or Reactive Power capability (see Section I, Item 4). In these cases, an entity should continue to have 12 months to analyze the issue and conduct the required testing.

MOD-025-3 is administratively burdensome with 30-day, 90-day, 180-day, 10-year and 180-day 10% change requirements which must all be tracked and verified. Consolidating reporting to 12 months eases this administrative burden.

"Facility" by itself is ambiguous, unclear and should be clarified according to NERC SDT writing rules. "Facility" could be either the individual generating resource or the entire BES plant. Therefore an auditor could require MOD-025 tests for all 1 MVA individual wind turbines or solar inverters at a given BES plant. The SDT needs to clarify the intent for Attachment 1, Section II, and item #2.

The SDT should remove the word "each" from Measures 1 and 2. The SDT should consider the use the terms such as "BES plant" meaning:

- Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or
- Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Related to Attachment 1, Section II, 2., if an applicable entity is expected to test "considering applicable modeling expectations of the respective Transmission Planner.", then their must be a requirement for the TP to publish applicable modeling expectations for MOD-025 testing.

NVE would request that the SDT clearly define all trends in Attachment 2, Figure 1 and 2 capability curves.

Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.

The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.

R1.3 would be better stated: "Submit the Real Power and Reactive Power verification to the associated Transmission Planner in accordance with Attachment 2."

Sections R1.3.1, R1.3.2, and R1.3.3 should be eliminated in order to maintain consistency with 1.1 and 1.2 referring to the attachment instead of re-stating what is in the attachment. This would avoid potential conflicts and confusion (which already appear to exist as currently drafted).

M1 could also be cleaned up to state: “Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each applicable facility and submitted the information to the associated Transmission Planner in accordance with Requirement R1.”

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	Yes
Document Name	

Comment

SIGE agrees with the language proposed although we would request consideration for a period longer than 30 days.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	Yes
Document Name	

Comment

BC Hydro appreciates drafting team’s efforts and the opportunity to review, and offers the following comments. Specific to Requirement R1 Part 1.3.1, BC Hydro’s interpretation is that a generic one-line diagram can be used for similar Facilities as long as the Attachment 2 information is clearly outlined, and a unique diagram does not have to be created for each site to demonstrate compliance with Requirement R1. BC Hydro requests that drafting team confirm whether this understanding is accurate.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
The proposed MOD-025-3, R1 language is acceptable, but replacing "Transmission Planner" with "Planning Coordinator" or "Planning Authority" may be better.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
NRG Energy generally agrees with the concept of the proposed timeline changes for testing and submission. The 30 day period from the completion of verification is a positive instead of completion from testing, although this proposed timeline may be tight to receive reports from vendors, review the report and submit. Recommend maintaining 90 days from completion of verification. We would also like to see clarification in the requirement noting that the verification was for a successful test. It is unclear what would happen if a GO's analysis revealed that a follow-up staged test was needed. Would that analysis be considered as a completed verification even if a retest was required? The requirement language is not clear.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG recommends separating the two requirements of what is presently 1.3.2 into two separate sub-sections, as follows: **1.3.** Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 30 calendar days after the verification date: **1.3.1.** One-line diagram representing the Facility;	

1.3.2. Composite capability curve;

1.3.3. PQ data table associated with the composite capability curve; and

1.3.4. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

OPG suggests this will better align with the ***four*** sections of the 'BES Facility Capability Report' described in Attachment 2.

Additionally, in the language for Measure M1, it should be clarified that only 'applicable' facilities are subject to the measure, as is done in R1; proposed language is as follows:

"Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each **applicable** Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R1."

Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Since Requirements R1-R4 contain a request for information that is needed for modeling, like MOD-032, Texas RE recommends this requirement include the GO submitting this information to the TP and PC. Texas RE is concerned that if the PC is not included, it may not receive the latest and most accurate modeling information.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree the language proposed in MOD-025-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. No comment TO responsibility.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
30 calendars day report to the Transission Planner is not enough time and creates additional tracking burden. Recommend removing the requirement to report data within a certain time after the verification, and change the requirement so that the reporting is included in the periodicity of the testing. For example, with a 10 calendar year periodicity, the verification and reporting would be required within 10 calendar years. The next period for verification would start at the verification date, not the reporting date. There should be an opt-out for R2 so that if the Transmission Planner is not using this verification, the Generator owner doesn't need to repeat the verification.	

R1 and R2 are exactly the same except R1 is for Generator Owners and R2 is for Transmission Owners. Couldn't they be a single requirement for both Generator and Transmission Owners?	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
In R2, Part 2.3, we believe the time allowed to submit the required information to the Transmission Planner should be "within 90 calendar days after the verification date" rather than 30 calendar days. This is consistent with MOD-025-2 (R3/Part 3.2) and allows the Transmission Owners that have been subject to MOD-025-2 to maintain procedural / controls practices related to this timing requirement in place. For verifications that can occur up to ten years apart (for an existing applicable Facility), the "urgency" of providing the verified information to the Transmision Planner within 30 calendar days vs. 90 calendar days seems unwarranted.	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question one.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Coproration (BHP) agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

While EEI supports the changes made regarding the staged verification testing and the required supporting materials, the following changes and clarifications are needed to Requirement R2 and its subparts:

1. Delete “of its applicable Facilities” from subparts 2.1 and 2.2 because this is already stated in Requirement 1.
2. Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.
3. The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.
4. Clarify the meaning of the term “verification date” used in subpart 2.3.
5. Clarify the meaning and use of the term “each Facility” as used in Measure M2. While entities are only obligated to provide verification of Real and Reactive Power capability for resources as identified in the Applicability Section, and in accordance with the BES definition; the use of “each Facility” seems to imply something different. To address this concern, consideration should be given to using the term “applicable Facilities” rather than “each Facility”.
6. Provide supporting attachments (i.e., composite capability curves, data tables, etc.) for all Applicable Facilities including
7. Provide guidance to support entity compliance and reporting for Facilities identified in Section 4.2.4 and 4.2.5.

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment

See the question 1 responses.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	

Comment

Agreement with the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	

Comment

Indicate if MOD-025-3 standard is applicable if the FACT device is designed only for the dynamic response and not modified in the steady-state power flow model.

Likes 0	
Dislikes 0	

Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Details of the submission to TP should be in Att. 2 (since used) and does not need to be listed under R1.3. In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group. In addition to these comments, Southern Company supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
The information should be submitted to the Transmission Planner within 180 calendar days after the verification date.	

Submitting the completed Attachment 2 documentation and data to the Transmission Planner within 30 days is not enough time for all the required peer reviews and Engineering analysis. We recommend changing the requirement to say "Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 180 calendar days after the verification date." The additional 150 days will allow time for a proper Engineering Analysis and Peer review and have a positive impact on the reliability of the planning model.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Again, as stated in question #1 the proposed time line of 30 calendar days after the verification date is not a sufficient amount of time. Tri-State recommends a timeline of 60 calendar days after the verification date.	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	No
Document Name	
Comment	
Please see commets in Quesiton 1	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	No
Document Name	

Comment	
Requiring entities to only check capability using paperwork is not going to show limitations that might be occurring. Actual performance tests or recorded operational data should be allowed as other means to demonstrate verification. See wording change above.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
No – Time frame should remain at 12 months and submission time stay at 90 days	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO seeks clarification on devices to include FACTs and justification on the need for testing of these devices. The standard needs to include a better definition of "Engineering review" or "engineering analysis" along with examples or prescribed methods of how this "engineering analysis" is to be conducted.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	

Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
It is hard to understand the benefit this will have on BES For the amount effort and cost involved in testing the SVCs.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	

Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not have any comments on R2 as it is not applicable to Generation Owners

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS generally supports the changes made to Requirement 2, but agrees with the following comments submitted by EEI on behalf of their memebers:

a) Verification timeframes should not be reduced from 12 months to 180 days within Attachment 1. Entities require the full 12 months in order to conduct suitable verification testing to gather accurate data that will support TP modeling studies.

b) The SDT should retain the 90 day timeframe for their Data submissions in accordance with Attachment 2 (see subpart 1.3). The data identified is significantly greater than what was required for MOD-025-2, as is the effort to ensure this data is properly reviewed, validated and adjusted to meet TP modeling needs.

c) Clarify the meaning of the term “verification date” used in subpart 2.3.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Additionally, MPC suggests referring directly to the applicable attachment for suitable measures.

"M2. Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each Facility, such as completed ***attachments*** *or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R2."*

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Please see the MRO NSRF's comments in question one.

Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	

BHC agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Refer to the responses in Question 1.	
Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the changes made regarding the staged verification of testing and the required supporting materials for Requirement R2. PG&E supports the EEI input for Q2 on their listed changes and clarifications for Requirement R2 and its sub-parts.	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the comments submitted by EEI.	
Likes 0	

Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	No
Document Name	
Comment	
The proposed timeline of 30-day submittal after verification date may not be sufficient time due to internal review and approval processes. Therefore, LADWP recommends the timeline of 60 days would be appropriate.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Please see the responses to question 1.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy seeks clarification on devices to include FACTs and justification on the need for testing of these. SVCs and other FACTS devices we view as not having moving parts which should limit their change in output and response over time and we seek clarification of their inclusion.

Also, the proposed MOD-025 revision transforms what was formerly a "required testing verification of demonstrated capability" into some form of an engineering analysis justifying a theoretical capability curve. The standard needs to include a better definition of "Engineering review" or "engineering analysis" along with examples or prescribed methods of how this "engineering analysis" is to be conducted.

In addition, FirstEnergy does not understand how the proposed revision to MOD-025 for reactive testing will provide any additional or more accurate information to the transmission planning entities since we currently already submit most of the needed information.

Generator capability curves are submitted via the annual MOD-032 submittals to PJM. Analysis of over/under excitation limiters are already included in the required PRC-019 documentation.

The excerpt below comes from the summary section of the NERC white paper "Implementation of NERC Standard MOD-025-2"

"The PPMVTF believes that there is value in performing the staged verification tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing may not be directly usable to represent the actual capability of the machine in power system models, and that the tests do not generally accomplish the stated purpose of the standard.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

The testing of a FACTS reactive resource may potentially (though obviously unintentionally) introduce risk to the system to which it is connected. Operating the system outside reasonable parameters is not acceptable for the purposes of testing. Testing of a FACTS reactive resource will be limited due to the constraints of the system at the time the testing is performed. It is quite possible that full output may not be obtained in either the capacitive or inductive direction (or both). Testing cannot require the disruption of the power system in the vicinity of the FACTS device, nor can it put that system at any risk due to the testing. The reason for the termination of the test at any output level should be documented in the test results with no further requirements due for further testing. As mentioned in the last paragraph of the white paper, an early termination of a test due to system constraints at the time of the test should not be construed to mean that the unit will always be limited to that maximum output. Any resulting limitation of the FACTS device in planning models would need to be determined after analysis of the cause of the limitation in the test results.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
While we have no specific issue with the language of the proposed requirement, it is nearly identical to the language for Requirement R1. We recommend combining Requirements R1 and R2 into a single requirement.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	

Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES Power Marketing.	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

As above for Requirement 1, OPG recommends separating the two requirements of what is presently 2.3.2 into two separate sub-sections to better align with Attachment 2, as follows:

2.3. Submit the following information per Attachment 2 to the Transmission Planner within 30 calendar days after the verification date:

2.3.1. One-line diagram representing the Facility;

2.3.2. Composite capability curve;

2.3.3. PQ data table associated with the composite capability curve; and

2.3.4. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

In the language for Measure M2, it should also be clarified that only 'applicable' facilities are subject to the measure, as is done in R2; proposed language is as follows:

"Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each **applicable** Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R2."

Likes 0	

Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Not applicable to GOs-only TOs.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation does not have any comments on R2 as it is not applicable to Generation Owners. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates drafting team's efforts and the opportunity to comment. Specific to Requirement R2 Part 2.3.1, BC Hydro's interpretation is that a generic one-line diagram can be used for similar Facilities as long as the Attachment 2 information is clearly outlined, and a unique diagram does not have to be created for each site to demonstrate compliance with Requirement R2. BC Hydro requests that drafting team confirm whether this understanding is accurate.	

Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE agrees with the language proposed although we would request consideration for a period longer than 30 days.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Please see BPA's comments pertaining to FACTS in question 8 (Technical Rationale) below.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC signed on to ACES comments: While we have no specific issue with the language of the proposed requirement, it is nearly identical to the language for Requirement R1. We recommend combining Requirements R1 and R2 into a single requirement.	

Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment TO responsibility.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE’s response to #1.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the language proposed in MOD-025-3 Requirement R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The proposed R3 language only requires TPs to perform a technical review of the provided documentation. They should be required to use the corrections-based documentation in their models, as explained in response #1 above.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro recommends that the language of Requirement R3 be revised to provide clarity as to whether the Transmission Planner's written response is required within 90 calendar days of their review or the receipt of the Generator Owner provided information.	
Likes 0	
Dislikes 0	

Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
As the data is not comparable to Transmission Planning models, a review is unnecessary. Also, Transmission Planners will not be equipped technically to review detailed test plan information. Refer to Question 1 comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The addition of the Transmission Planner (TP) 90-day requirement to document that it received, reviewed and updated capability information is burdensome and unnecessary. Entities already provide the TP with data. Models fundamentally rely on information provided to modeling and planning personnel who use their experience to develop the parameters used in those models. Mandating MOD-025 data be placed in models is flawed by taking the human out of the equation. The intent of MOD-025-3 from reliability standpoint does make sense, however, in practice results are rarely actuals, but derived approximates for Pmax, Pmin, Qmax and Qmin. Therefore, the data should not be mandated in any system related to producing “accurate” models.	

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation agrees with a 90-day requirement to receive feedback regarding models from the Transmission Planner; however, we are concerned that the additional data that this draft Standard is proposing may not even be used by the Transmission Planner. If this Standard is requiring the GO provide the additional data such as a one-line diagram, composite capability curve and associated PQ data table, documentation showing the engineering basis, verification methodology and/or applicable data for the verification method then Constellation suggests that the proposed Standard language be modified to allow an exception from certain parameters based on the Transmission Planner's individual needs for modeling. Kimberly Turco on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	

Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
Please provide the details behind the expectations for the Transmission Planner to identify technical concerns as it relates to notification from the TP to the TO and/or GO. Would this require offline planning studies to evaluate the data provided? More detail is needed in this requirement to identify the criteria related to "technical concerns."	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company suggests deleting R3 in its entirety as it is purely administrative. The addition of the Transmission Planner 90-day requirement to document that it received, reviewed and possibly, but not certainly, updated capability information is burdensome and detrimental to system reliability. In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group. In addition to these comments, Southern Company supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
MOD-025 tests are currently performed under a restrictive set of assumptions (i.e., a particular snapshot of an operating condition), and as such the capabilities of the equipment as tested tend not to be well determined. Given this, the responsibility for determining any technical concerns with the Real and Reactive Power capability information need to be improved upon to provide properly verified and correct unit capability data, and compliance responsibility for this should rest completely with the Generator Owner, not the Transmission Planner. But as they exist now, MOD-025 tests provide test data that Transmission Planners do not have the capability or expertise to evaluate. Given this, it is inappropriate to assign Transmission Planners the job of technical verifier to Generator Owners, and thus placing compliance responsibility on the Transmission Planner function for responding back to GOs and TOs for these MOD-025 verifications is unnecessary, burdensome, and of negligible value to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The addition of the Transmission Planner 90-day requirement to document that it received, reviewed and updated capability information (to whatever system) is burdensome and detrimental to system reliability.	

Models fundamentally rely on information provided to modeling and planning personnel who use their experience to develop the parameters used in those models. Trying to mandate MOD-025 data be placed in models is again fundamentally flawed, taking the human out of the equation. NERC and system operators alike have all agreed that a human must ultimately be in the loop, using their experience and professional judgement to help guide the system. Models are no different.

The MOD-025 testing standard is fundamentally flawed and almost never reflects the true capability of the BES plant. Therefore, the data should not be used in any system related to producing “accurate” models of any sort.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

The proposed MOD-025-3 R1 and associated sub-bullets require GOs to verify facility real/reactive power capability via testing per Attachment 1 as well as provide a one-line diagram representing the Facility, composite capability curve and associated PQ data table, and documentation showing the engineering basis, verification methodology and/or applicable data for the verification method per Attachment 2. However, the proposed R3 language only requires TPs to perform a technical review of the provided documentation. The NAGF suggests that the proposed language be modified to required TPs to use the provided documentation in their models.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

The addition of the Transmission Planner (TP) 90-day requirement to document that it received, reviewed and updated capability information is burdensome and unnecessary. Entities already provide the TP with data.

Models fundamentally rely on information provided to modeling and planning personnel who use their experience to develop the parameters used in those models. Mandating MOD-025 data be placed in models is flawed by taking the human out of the equation.

The intent of MOD-025-3 from reliability standpoint does make sense, however, in practice results are rarely actuals, but derived approximates for Pmax, Pmin, Qmax and Qmin. Therefore, the data should not be mandated in any system related to producing “accurate” models.

Likes 0	

Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

The requirement effectively brings the TP into the standard simply to provide an administrative function. It is agreed that any technical comments by the TP should be provided in writing if there are any comments at all. However, forcing the TP to provide a comment that there is or is not a technical issue is not necessary or appropriate for inclusion in a Reliability Standard. Additionally, the selection of a 90-day response period appears arbitrary.

If this requirement is retained, it should be reworded to state that any technical comments should be documented and provided in writing. The 90-day window should also be removed as it is possible the TP could come up with additional technical concerns beyond 90 days.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

The transmission planner should not be obligated review this data, if they did not request it, and there should not be a time limit on their review. Tracking the timing of the review creates unnecessary burden on the TP.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

No comment.

Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Requirement R3 is overly broad and ambigiuous, implying that a Transmission Planner shall review information submitted by **any** Generator Owner or Transmission Owner. The required obligations of the Transmission Planner should be limited to review of the information submitted by the Generator Owners or Transmission Owners for which it serves as Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
MH agrees that the new R3 requirement provides the needed feedback mechanism to address Transmission Planner's concerns regradings any technical issues that it identifies with the Real or Reactive Power capability information. It should be left up to the Transmission Planner to communicate to the Generation and Transmission Owners the information required to address their concerns. The most efficient way to address the model accuracy issues is to encourage dialogue between entities to ensure that verifications are accurate and appropriate for the needs of the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
However, WECC defers to the TPs as to whether 90 days is an adequate amount of time to address this requirement.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the proposed language in Requirement R3.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with a 90-day requirement to receive feedback regarding models from the Transmission Planner; however, we are concerned that the additional data that this draft Standard is proposing may not even be used by the Transmission Planner. If this Standard is requiring the GO provide the additional data such as a one-line diagram, composite capability curve and associated PQ data table, documentation showing the engineering basis, verification methodology and/or applicable data for the verification method then Constellation suggests that the proposed Standard language be modified to allow an exception from certain parameters based on the Transmission Planner's individual needs for modeling. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	

Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the language proposed in MOD-025-3, Requirement R3.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI. PGE also suggests that the Standard language identifies when the 90 calendar days is initiated. Example "within 90 calendar days of receipt of the GO/TO submission of the capability verification information."	
Likes 0	
Dislikes 0	
Response	

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE’s response to #1.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

4. Do you agree the language proposed in MOD-025-3 Requirement R4? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
There should only be a time limit on this, if the length of time since an accepted test has surpassed the periodicity for the testing period. For example, with a 10 year periodicity, say that a test was completed and accepted in year zero. At year 8, if the GO submits a verification to the TP and the TP has concerns, the GO should not have additional burden to respond within 90 days just because they submitted a test early.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The third bullet of this requirement is circuitous in that it requires a plan “mutually agreed upon with its Transmission Planner” be provided to that Transmission Planner (TP). If it has been “mutually agreed upon” by the TP, it seems it would need to be shared with the TP prior to the 90 calendar day date. We suggest removing the “mutually agreed upon with its TP” stipulation and just require a plan be submitted to the TP, similar to what is required in Requirement R3 of MOD-026 and MOD-027.	
Likes 0	

Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Reference the comment to question #3. Response to any relevant technical comments would more appropriately be included under R1 & R2 of the proposed MOD-025.	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question three.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF recommends that the language in R4 be revised to be similar to that used in MOD-032-1 R 3.2: "Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the Transmission Planner".	
Likes 0	

Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
See the question 3 responses.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Modify R4 to read: Each Generator Owner or Transmission Owner receiving a notification of a technical concern under Requirement R3 shall provide “an initial” written response to its Transmission Planner within 90 calendar days containing one of the following..."	
Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company suggests deleting R4 in its entirety as it is purely administrative. In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group. In addition to these comments, Southern Company supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
This requirement should align with MOD-032-1 R3.2 to provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation agrees with the required timeframe, however, requests the addition of the condition "provide the response within 90 calendar days of receipt, unless a longer time period is mutually agreed upon by the notifying Planning Coordinator or Transmission Planner" to include situations that require additional troubleshooting that takes longer than the 90-day period to answer the technical concern. This language would align with other NERC Standards (e.g., MOD-032-1 Requirement R.3). Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation agrees with the required timeframe, however, requests the addition of the condition "provide the response within 90 calendar days of receipt, unless a longer time period is mutually agreed upon by the notifying Planning Coordinator or Transmission Planner" to include situations that require additional troubleshooting that takes longer than the 90-day period to answer the technical concern. This language would align with other NERC Standards (e.g., MOD-032-1 Requirement R.3). Kimberly Turco on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No

Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question three.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES Clean Energy believes that for a "mutually agreed upon" plan to be developed, more than 90 days may be needed to receive confirmation from a Transmission Planner that the plan is agreed upon. AES Clean Energy recommends increasing the timeline, removing mutually acceptable, or requiring that Transmission Planners respond to test plans with enough time for a Generator Owner to modify and resubmit the plan.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	

Comment	
WEC Energy Group supports the comments submitted by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The Requirement R4 mandates that the GO's plan be "mutually agreed upon" with the TP. Similar wording was used in MOD-026-2 Draft 1 (reference NERC Project 2020-06) and in response to comments is being considered for removal (Draft 2 has not been posted on the project page at the time of this submission). BC Hydro's view is that the mutual GO-TP agreement is not necessary as the Facility Owner will need to provide information compliant to R1 and/or R2 or a technical justification. BC Hydro recommends that the R4 language be revised to remove the "mutually agreed upon" wording from the second bullet. If the intent of the drafting team is to provide the TP sign off authority on the GO plan, then this would be better suited in a standalone Requirement and additional clarification should be provided in the associated Technical Rationale document.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	

Answer	No
Document Name	
Comment	

The language in R4 should be revised to be similar to that used in MOD-032-1 R 3.2: “Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the Transmission Planner”.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.

Answer	Yes
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI. PGE also suggests that the Standard language identifies when the 90 calendar days is initiated. Example “within 90 calendar days of receipt of the TP notification.”

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI supports the language proposed in MOD-025-3, Requirement R4.

Likes 0	
Dislikes 0	

Response

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese

Answer	Yes
Document Name	

Comment

Exelon agrees with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E supports the proposed language in Requirement R4.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

MOD-026 and MOD-027 include a provision for the GO to request an extension. For continuity, BPA recommends the same provision be included in MOD-025.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	Yes
Document Name	

Comment

However, WECC defers to the GOs and TOs as to whether 90 days is an adequate amount of time to address this requirement.

Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD

Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE’s response to #1.	

Likes 0	
Dislikes 0	
Response	

5. Do you agree the language proposed in MOD-025-3 Attachments 1, 2, and 3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP recommends that the Project 2021-01 SDT pursue a similar periodicity as currently being pursued for MOD-026-2 by the Project 2020-06 SDT. In that project's most recent draft of MOD-026-2, the periodicity table allows 365 days from COD for the GO or TO to verify modeling of new facilities, and 180 days allowed for modification of facilities already in service which require model reverification. In MOD-026's most recent revisions, if 180 days is found to not be sufficient, the facility owner may send a verification plan to the TP within 180 days and then has 365 days following plan submittal to do the verification and provide to the TP. We recommend a similar timeframe and approach to be used in Project 2021-01 for MOD-025-3.

Likes 0	
Dislikes 0	
Response	

Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

1) Regarding the intent of providing the Composite Capability Curve (CCC) at 1.0 per-unit: Kestrel has concern that provided the CCC and associated limiters/limiting functions at 1.0 per-unit will not serve as practical means to assess unit capability. A unit/plant's capability curve is, in reality, a three-dimensional figure which varies based on voltage. By providing the CCC at 1.0 pu, we would be removing the context associated with the plant being over-excited or under-excited. It is well-known that limiters will shift relative position vs equipment capability based on voltage, and that many limiters have inherent modification based on voltage level (e.g. most Under-Excitation limiters adjust based on square of voltage, although the exponent value can be configurable depending on controls type).

As such, attempting to correlate steady state operating points, and the results that are gathered during staged testing, will not align with the CCC plotted at 1 per-unit voltage. Kestrel's suggestion would be to populate the CCC at steady state operational voltage bounds associated with the plant (e.g. +/-5% for many synchronous machines, although this can be conditional if there is a different voltage limitation like auxiliary loads).

2) Kestrel identifies that staged testing is no longer a requirement. In previous versions of the Standard, a baseline through testing was required, after which operational data could be used. Kestrel has concern that until proven, engineering analysis is just that. In our experience performing reactive capability testing (thousands of units over 2 decades), the number of times in which unexpected 'phenomena' has been observed is significant. Short examples being unknown protection elements or failure of control / power exporting hardware. Kestrel recommends that for a given instance of hardware, a staged test should be performed which is then to be correlated to engineering analysis. From that point forward, engineering analysis or operational data can be used to re-verify performance. This suggests that replacement of major components which impact active/reactive capability (generator, excitation system, turbine, turbine-governor, etc) may warrant confirmation testing.

3) Regarding Attachment 1 Section III item 4 – there are a significant number of IBR facilities which operate in power factor or reactive power control mode, even though they do have an option to operate in voltage control mode. Based on the wording in the draft standard, my interpretation is that any of these sites would be forced into a non-typical mode of operation for the purpose of the test. Is this true / the intent of the wording? If not, suggest caveat for if the plant does happen to operate in a non-AVR mode.

4) Many of the data points given in Attachment 3 are static and/or rated values (voltage ratio, impedance, X/R ratio, tap position for off-load tap change transformers). There had been instances of confusion with application to MOD-025-2, in that it isn't practical to list these static values in every instance of a test (minimum load leading/lagging, max load leading/lagging). While this is certainly relevant information which should be included within the test report, it seems that the intent of Attachment 3 is to be specific for the individualized test and values which change based on test condition. Suggestion to remove static/rated information from Attachment 3, with potential to specify the inclusion of this information elsewhere in the test report.

Suggested inclusions for when applicable or as available: net head (hydro units), generator or exciter field voltage (sync machines only), wind speed (wind turbines), solar irradiance (PV solar), on-load tap changer (OLTC) position, declaration of specific reactive compensation component status (e.g., reactor bank 1 in-service, bank 2 out-of-service), declaration of which distributed generating resources are offline, calculated collector system losses (or reactive power generated).

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy seeks clarification on devices to include FACTs and justification on the need for testing of these. SVCs and other FACTS devices we view as not having moving parts which should limit their change in output and response over time and we seek clarification of their inclusion.

Also, the proposed MOD-025 revision transforms what was formerly a "required testing verification of demonstrated capability" into some form of an engineering analysis justifying a theoretical capability curve. The standard needs to include a better definition of "Engineering review" or "engineering analysis" along with examples or prescribed methods of how this "engineering analysis" is to be conducted.

In addition, FirstEnergy does not understand how the proposed revision to MOD-025 for reactive testing will provide any additional or more accurate information to the transmission planning entities since we currently already submit most of the needed information.

Generator capability curves are submitted via the annual MOD-032 submittals to PJM. Analysis of over/under excitation limiters are already included in the required PRC-019 documentation.

The excerpt below comes from the summary section of the NERC white paper "Implementation of NERC Standard MOD-025-2"

“The PPMVTF believes that there is value in performing the staged verification tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing may not be directly usable to represent the actual capability of the machine in power system models, and that the tests do not generally accomplish the stated purpose of the standard.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

1) Please see the responses to questions 1 and 3.

2) In Attachment 1, section I. 4, depending on the size of the unit, 10% may or may not be a big MVA number. Therefore, it is suggested to change the sentence to "10% or xx MW(fixed number, it can be either 2MVA, 3MVA or 5MVA) whichever is the smallest".

3) In Attachment 1, section III. 6, during the stage test, is it required to let the machine run for a time period (say 30min) at the test point?

4) In the diagram on page 17, what does it mean for “Other Point Of Interconnection”? Should the whole station SLD be provided? All station service transformers and station load should be clearly marked and listed on the SLD. In case of several station service transformers in parallel operation, the status and loading information of each station service transformer should be provided so that the detailed station load can be calculated.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

The changes to this standard are quite extensive and we appreciate the large amount of time and effort that the SDT put into making meaningful updates. However, we do not believe that 180 calendar days is a sufficient amount of time to complete the staged testing and engineering analysis for new applicable Facilities identified in Attachment 1, Section I, Item 2. As new facilities will be unlikely to have sufficient operational data for the purposes of MOD-025 verification, we recommend that this section be reverted to the previous value of 12 calendar months.

Furthermore, in Attachment 1, Section I, Item 5, the outage duration must be >= 180 calendar days AND overlap the scheduled verification date in order to be allowed to perform the verification within 180 calendar days of the Return to Service (RTS) date. Consider the following scenario showing why a defined outage timeframe could be an issue (Note: all dates and timeframes are completely arbitrary and for illustrative purposes only):

{C}· Entity XYZ is the registered GO for Unit X.

{C}· Unit X is a 100 MW Combustion Turbine (CT) that was last verified 9 years, 7 months ago per MOD-025-3.

{C}· Unit X is scheduled to begin a 90-day hot gas path outage in 2 weeks (i.e. 9 years, 7 months, 14 days since last verification date).

{C}· Due to the extensive nature of these types of outages and the massive quantity of worn-out components being replaced with new like-in-kind components, the unit capability will increase following the outage; however, the increase will likely be < 10%.

{C}o Therefore, in order to provide the TP with the most accurate data, the GO plans to perform the MOD-025 verification with the new components installed immediately post RTS (i.e. within the 10-year verification period).

{C}o Based on the currently scheduled dates, this plan leaves plenty of margin to complete the MOD-025 verification in a timely manner.

{C}· During the outage, a major issue is discovered requiring extensive rotor work on the CT.

{C}o These rotor repairs extend the length of the outage by an additional 51 days for a total outage time of 141 calendar days.

{C}· As the extended outage time is < 180 days, Entity XYZ is now in violation of MOD-025-3 due to not performing the verification within the 10-year period.

{C}o Example schedule:

{C}§ Last date of verification: 08/31/2013

{C}§ MOD-025-3 Verification Deadline per R1: 08/31/2023

{C}§ Outage Start Date: 04/14/2023

{C}§ Projected Outage End Date: 07/13/2023

{C}§ Actual Outage End Date: 09/02/2023

In the Scenario above, the GO is left with 3 possible choices. Either A) perform the verification prior to the scheduled outage or B) risk a violation if the outage gets extended or C) to extend the outage >= 180 days. In our opinion, none of the above choices are optimal. Please consider the following options for modifying the verbiage in Item 5.

Option A)

“Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years.”

Option B)

“Verify an existing applicable Facility prior to its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years.”

Note: Option A is the preferred option.

Likes 0	

Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

The Att. 1, sect. II, part 5, first bull-dot requirement to, "Perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations," should be deleted. A review of "all" information is not practical, nor are complicated preparations necessary. All one needs to do is check the OEL and UEL curves in the PRC-019 study. No new information needs to be developed before performing MOD-025 tests.

The reference to a staged test date within 365 days of the staged test date should be removed from the second bull-dot in Att. 1, sect. II, part 5.

Att. 1, sect. II parts 6 and 7 should be deleted, along with the composite capability curve (CCC), PQ curve data table and, "documentation showing the engineering basis and verification methodology," of Att. 2. The tests required by MOD-025 remain quite straightforward – max lag, max lead, min lag and min lead – and anything beyond MW, MVAR and voltage data for these four points is pointless because, as described above, even if TPs/ISOs can be forced to receive the additional material mandated by MOD-025-3 they (or at least the ones we deal with) do not make use of this information.

Att. 1, sect. II parts 6.3 and 7.3 are particularly objectionable. There are always operational limitations holding Real Power below the stator thermal limit on the generator OEM's D-curve – the boiler/turbine capability. This value varies widely with operating conditions, so constructing a MOD-025-3 curve in this respect for some nominal "1.0 per unit" ambient conditions would serve no purpose. The same is true for MVAR operational limitations as regards generator cooling. Having to calculate the ambient conditions beyond which generator windings temperature alarms will annunciate prior to reaching the OEL would be a very time-consuming exercise, involving supplemental testing, with again no apparent willingness of TPs/ISOs to use this information.

The Pmax and Pmin parameters bear definition, since it is presently unclear whether they refer to normal or emergency output. We suggest that Pmax be the maximum power that a GO/GOP bids into the market, +/- 5% since it is not practical to balance on a knife edge during tests. Pmin should be the lowest power for everyday operation, not the emergency minimum value, since pushing equipment to extremes for the min-load tests adds no reliability value.

"Transformer Voltage Ratio," in Att. 3 should be changed to, "Transformer Windings Ratio." The windings ratio of a transformer is a fixed value, while the voltage ratio is a function of windings ratio and voltage drop. The voltage drop depends in turn on the MW and MVAR being handled.

Windings ratio and tap settings data for unit aux, station aux and other aux transformers should be removed from Att. 3. TPs/ISOs in our experience do not model below the generator bus level, so they will have no use for this information.

Guidance is needed for the Section III item 3 criterion, "Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state condition." Reactive output is raised or lowered slowly when approaching OEL/UEL or voltage limits during testing, so any thermal constraints that are encountered (e.g. generator high windings temperature alarms) appear almost immediately. The few minutes of dwell time needed to collect data is therefore sufficient in our experience, so there is no need for the one-hour max lag hold-time presently required or for some vague "sufficient" criterion, but it is not practical to computationally prove this point.

Changing the MOD-025 periodicity from five years to ten is a step in the right direction, but this standard should also have the same capacity factor exemption that is applied for MOD-026 and MOD-027. Our principal cost of running VAR tests is that of bidding-in to the market at a loss certain peaking units that almost never run except under demand situations so severe that the ISO forbids testing. The ratio of reliability benefit to GO/GOP burden in such cases is unjustifiably low.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro has the following comments on Attachment 1 of MOD-025-3 Draft 1:

Per Section I Bullet 4, the amount of time available to the GO/TO to verify changes has been cut down from 12 calendar months to 180 calendar days. BC Hydro's assessment is that the requirement to perform verification "within 180 calendar days of the discovery of a change that… and is expected to last more than 180 calendar days" is too strict. In some cases, once a change happens, it takes some time to complete the assessment necessary to determine how long the change will last. While the GO/TO is trying to confirm if the change is going to last longer than 180 days, the clock is ticking and the time available to the GO/TO to perform verification (if it becomes applicable) dwindles rapidly. MOD-025-2 currently allows for verification within 12 calendar months.

BC Hydro recommends that the same 12 calendar month timeline be maintained in the new draft for verification.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments submitted by the NAGF.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

The SERC Generator Working Group suggests adding clarification on the dates for completion and submittal.

In attachment 1, #4, need more clarity on what is meant by "discovery of a change" and "is expected to last"

Additionally, the SERC GWG agrees with the comments provided by ACES

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Refer to response in Question 1.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Please see the MRO NSRF's comments in question one and three.

Attachment 1, Section I, #2--We disagree with shortening the verification of a new facility from 12 months to 180 days. A new facility, such as a wind farm, may not have the ability to be at full capacity when the farm is new.

Attachment 1, Section II, #5--We believe that examples of an engineering review should be included to provide guidance. Attachment 1, Section III, #2--Provide an example of clarification of and engineering analysis to provide guidance. Attachment 3 Page 22--the addition of Transformer Impedance overlaps with VAR-002, R5 and is unnecessary since this is already required in other standards.

For variable generating resources, such as wind, solar, or run-of-river hydro, and non[1]variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line.   Staged testing or operational data shall be recorded from a time period when the Facility output of Real Power is forecasted to be greater than 75% of the Facilities nameplate total Real Power capability or at Real Power capability that allows the GO to demonstrate its full Reactive Power capability. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s)the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data. 9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached; 9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Attachment 1

Section I. Peridocity of verification

Recommend keeping existing points 2 and 4, consider deleting the rest, and consider adding event driven verification.

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be reverified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

1. Verify each new applicable Facility within 12 calendar months of its commercial operation date.

2. Verify an existing applicable Facility within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 12 calendar months.

3. Verify an existing applicable Facility within 12 calendar months of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Section II. Verfication for applicable Facilties

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3.

Suggested edit:

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability with all equipment expected to be in-service for normal operation. The requirements listed in the last sentence add cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.

Attachment 2

Recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No

Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum. Additionally, attachment 1, section II, paragraph 5, bullet 1 (pg 13), states that entities must “perform an engineering review of **all** Real and Reactive Power Facility capability information…”. The use of the word “all” is problematic. This should be modified to either explicitly list all important elements that the SDT thinks whould be included or allow an entity to use engineering judgement to determine which elements of “capability information” should be considered. Attachment 1, section 2, paragraph 6.2 (pg 13) seems to overlap with PRC-019-2. Can the SDT please comment on the rationale that supports including this language in MOD-025-3? Attachment 1, section III, paragraph 3 (pg 15) uses the phrase “for a sufficient time”. This phrase is problematic because is is unclear what is meant by “sufficient”. This reference should either be removed or replaced with a specific period of time. Attachment 1, section III, paragraph 6, uses the language “until a limit is reached”. This could be interpreted to be contradictory to Attachment 1, section III, paragraph 3, which requires that “Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.” MPC suggests changing paragraph 3 to state that “Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions **or until a limit is reached**.”	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS does not agree that the 12 month verification timeframe should be reduced to 180 days in Parts 2, 4, and 5 for the reasons outlined in our response to Questions 1 and 2 above.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment	
Attachment #1: Section 1, Item 1: Constellation requests that the proposed language be modified to state that the verification date represents the engineering analysis completion date rather than the testing date. Section 1, Item 2: Constellation does not agree with the verification of each new applicable Facility within 180 calendar days of its commercial operation date. There may be reasons for a company to declare "commercial operation date" prior to actual day-one operational date due to regional and state differences (e.g., project financing, commissioning testing). Constellation therefore recommends revising the language to state "within 180 days of initial synchronization to the grid" Section 1, Item 3: Constellation agrees with the 10-year periodicity; however, Transmission Planners typically have more conservative testing requirements. As previously mentioned, the data and periodicity for testing is dictated by the Transmission Planners and therefore providing such specific requirements in MOD-025 will continue to result in discrepancies in data reported to meet the Transmission Planner requests and evidence documented to meet the Standard requirements. Section 1, Item 4: Constellation does not agree with the 180-day timeline for a change in capacity due to economic concerns. Wind and hydro generating units will now be required to perform max leading and lagging testing. It is unclear if first test has to be staged as the form now requires a composite curve, PQ table and documentation showing methodology. Section 3, Item 5: Constellation recommends rewording this as IBR facilities operate only in VAR or PF control modes. Kimberly Turco on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Attachment #1: Section 1, Item 1: Constellation requests that the proposed language be modified to state that the verification date represents the engineering analysis completion date rather than the testing date. Section 1, Item 2: Constellation does not agree with the verification of each new applicable Facility within 180 calendar days of its commercial operation date. There may be reasons for a company to declare "commercial operation date" prior to actual day-one operational date due to regional and state differences (e.g., project financing, commissioning testing). Constellation therefore recommends revising the language to state "within 180 days of initial synchronization to the grid" Section 1, Item 3: Constellation agrees with the 10-year periodicity; however, Transmission Planners typically have more conservative testing requirements. As previously mentioned, the data and periodicity for testing is dictated by the Transmission Planners and therefore providing such specific requirements in MOD-025 will continue to result in discrepancies in data reported to meet the Transmission Planner requests and evidence documented to meet the Standard requirements. Section 1, Item 4: Constellation does not agree with the 180-day timeline for a change in capacity due to economic concerns. Wind and hydro generating units will now be required to perform max leading and lagging testing. It is unclear if first test has to be staged as the form now requires a composite curve, PQ table and documentation showing methodology	

Section 3, Item 5: Constellation recommends rewording this as IBR facilities operate only in VAR or PF control modes.

Alison Mackellar on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC

Answer	No
Document Name	

Comment

Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	No
Document Name	

Comment

Section I. Periodicity of verification:

2. Disagree with the 180-calendar day requirement to verify each new applicable facility. A situation could arise where the 180-day requirement cannot be done due to constraints on the grid.

3. Verbiage should be similar to MOD-026 and MOD-027 to include ten-year anniversary from the last verification date.

6. Disagree with the 180-calendar day requirement to verify each new applicable facility. A situation could arise where the 180-day requirement cannot be done due to constraints on the grid. Also, there is no clear direction on what you should do if the issue is resolved after the 180 days and the subsequent change is back to nameplate value.

Section II. Verification specifications for applicable Facilities:

5. Realistically the D-Curve from PRC-019 should be what we use. If we add Pmax and Pmin requirement to PRC-019 then that addresses the needs for the current proposed MOD-025 requirements and makes MOD-025 unnecessary.

6. Composite capability curve should also include a line for Pmax included in transmission models as this may be different from operational Pmax. Transmission planning model often have Pmax set as the value define in the GIA which cannot be changed by the Transmission Planner.

Section III. Staged test and operational data specifications

Sufficient time should be defined. If the sufficient time is defined by the applicable entity it will be fine.

Likes 0	
Dislikes 0	

Response

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese

Answer	No
Document Name	

Comment

Exelon agrees with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #5.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO reommends pursuing a similar periodicity as currently being pursued for MOD-026-2 by the Project 2020-06.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Verification of reactive power capability as defined in attachment 1 is not well defined. Several previous tests were not able to accomplish documented limits due to system conditions. Overall, in our opinion, there is not much value to performing this particular test.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	

Attachment 1:

1. Says “discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating”. This should be changed to “discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the previously submitted capability or the nameplate rating if there has not been a previously submitted capability”.
2. Has in Section II part 2 a statement “that are part of an applicable Facility greater than 75 MVA”. This should be changed to “that are part of an applicable Facility greater than 50 MVA” since substantial parts of the BES are impacted by 50 MVA devices/generators.
3. Says “operating conditions that dictate the power capability, for example H2 pressure”. This should be changed to “operating conditions that dictate the power capability, for example H2 pressure”.

Attachment 2:

1. Says “changes may be made to this form, provided that all required information is reported”. Who determines what is “required information” – the PA/PC, TP, TO, GO?

2. Has a statement “The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above.” There does not appear to be a Point XX in the one-line diagram.
3. Has a table “PQ Curve Data Table”. In this table, the rows are described a Pmin + some part of Range. For synchronous condensers or FACTS devices where real power consumption can vary depending upon the reactive power output, how is this table expected to be completed?

Attachment 3:

1. Says “changes may be made to this form, provided that all required information is reported”. Who determines what is “required information” – the PA/PC, TP, TO, GO?
2. The form is also quite poorly developed. Even for a test of a very standard synchronous generator connected to the BES by a single transformer, the Attachment 3 form is not good. Examples are:
3. The language says “Check all that apply” whereas it should say “Check the one which applies” since it would not be possible, or at least not very clear, what to record in the “Data Table” if the “Over-excited Maximum Load Reactive Power Verification” and “Under-excited Minimum Load Reactive Power Verification” were both checked.
4. The “Summary of Test / Operational Data” has an entry for “Transformer Tap Setting”. What about transformers which have both high-side and low-side taps? What is the purpose of “Transformer Voltage Ratio”?

Likes 0	
Dislikes 0	

Response

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

Attachment 1 potentially requires only a paperwork exercise to verify capability. Actual performance tests or recorded operational data should be allowed as other means to demonstrate verification. Section II sub-sections 1 and 2 should be changed to use the BES definition instead of 20 MVA gross nameplate rating.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	

Comment

It is constructive to allow flexibility by the Functional Entities to establish methodologies for reporting Real and Reactive Power capability, but there is a need for a common basis, understanding, and consistency on a shared methodology between the Functional Entities. Little guidance is provided to establish a common basis to determine and report Real and Reactive Power capability. There is a need to better identify the acceptance criteria to determine when a reported value is "verified" after a random mixture of possibilities of staged testing, operational evidence, and engineering analysis. The absence of this criteria increases the likelihood for R4 notifications with more conflict to attain a mutually agreed upon resolution. The drafting team should investigate if reasonable acceptance criteria can be consistently applied across the Functional Entities. Better guidance or endorsement is needed in the standard to validate the acceptance of engineering analysis of reactive capability of a synchronous generator under system voltage deviations that are impossible to replicate for a staged test under normal operating conditions. The full weight of the standard needs to whole-heartedly endorse the use of engineering analysis to supplement or establish reactive capability that can't be overruled by a Transmission Planner's objections; this is needed to overcome the past practices of ISOs to determine a generating unit's reactive capability by only accepting the recorded readings of a staged test, regardless of the system operating conditions.

A significant reason for the SAR was that engineering analysis and calculations were not permitted as sufficient justification why a machine did not reach its stated capability due to system operating conditions at the time of a staged test. Those familiar with the interaction of a synchronous generator with a transmission system know that a generator can easily produce more lagging reactive when system voltage is low and produce more leading reactive when the system voltage is high. The Attachments should specify to allow engineering analysis to calculate and report a generating unit's reactive power output for the following conditions:

1. For leading power factor operation, it is acceptable to calculate and report the generator reactive output when the system voltage is 2% about the schedule voltage (target system voltage for the generator to normally maintain).

2. For lagging power factor operation, it is acceptable to calculate and report the generator reactive output when the system voltage is 2% below the schedule voltage (target system voltage for the generator to normally maintain).

3. Synchronous generators are thermally capable of continuous operation within the confines of their manufacturer's reactive capability curves over the ranges of ±5% in voltage as specified in IEEE C50.13.

Regarding the Attachments:

The options in Attachment 1, Section II, item 5, provided on how to comply with the standard are loose. This will end up creating issues to determine what actual verification should intel. The sections after provide the type of information to be included but doesn't have technical criteria for meeting verification.

The SDT should reword Attachment 1. Section 1, Line item 5 to clarify the If/Then statement. Attachment 1-Section I, Line item 5 should be a sub requirement of Line item 3 as an exception to extend the ten-year requirement.

In addition, Attachment 1-Remove Section II., 3.1, one-line requirements; only require the stated objective of a simplified one-line diagram, as shown in Attachment 2, Section I. The stated requirement of 3.1 ("The one line representing the Facility shall include all auxiliary equipment expected to be in-service for normal operation") implies that the one line must display the details of "all" auxiliary equipment. This contradicts the concept of a simplified one-line. The description of "all auxiliary equipment" is too broad, ambiguous, and overly inclusive of miniscule loads connected to external sources. Including "all auxiliary equipment" requires the accounting of inconsequential loads outside the power block of a large generating unit, which is impractical and unnecessary for the objective of the standard. Add a provision that the inclusion of monitoring points D and E of Attachment 2, Section I, are not required if the operating auxiliary load at these points are less than 1% of generator nameplate MVA.

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	No
Document Name	
Comment	

We have the following concerns with the generator testing prescribed in Attachment 1:

· Attachment 1 does not adequately address the real power output and conditions. Real power generation will vary greatly for gas turbine generators based on ambient weather conditions. Although not as significant as the variation in real power output of gas turbines, steam units have a varied output based on condensing temperatures. Real power testing should be conducted with all applicable weather conditions being recorded along with the corresponding output. Transmission line capacities vary with ambient temperature, therefore the output of the real power generating capacity at different conditions needs to be provided.

· The ten-year test period is too long. Although changes of more than 10% are to be reported and tested, over that time there is too much opportunity for things to change and not be reported. Testing at least every five years assures that the generating capacity information is adequately maintained.

Attachment 1

Section I. Peridocity of verification

Recommend keeping existing points 2 and 4, delete the rest, and add event driven verification.

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be reverified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

{C}1. Verify each new applicable Facility within 12 calendar months of its commercial operation date.

{C}2. Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days.

{C}3. Verify an existing applicable Facility within 180 calendar days of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Section II. Verfication for applicable Facilties

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3.

Suggested edit:

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for with all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8. *The requirements listed in the last sentence add cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.*

Attachment 2

Mildly recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Strongly recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability

Attachment 1, Section II, #5--We believe that examples of an engineering review should be included to provide guidance. Attachment 1, Section III, #2--Provide an example of clarification of and engineering analysis to provide guidance. Attachment 3 Page 22--the addition of Transformer Impedance overlaps with VAR-002, R5 and is unnecessary since this is already required in other standards.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

Regarding Attachment 1:

In Attachment 1, Section I, Item 2, the term ‘commercial operation date’ should be defined. Since this term will set the date by which verification must take place, it could be difficult to determine compliance without a clear definition of what constitutes the start of the 180 day period.

In Attachment 1, Section I, Item 3, OPG would recommend making reference to Real Power and Reactive Power verifications per Requirements R1.1, R1.2, R2.1, or R2.2, since active power verification and reactive power may be verified separately, and have separate required reverification dates; proposed language is as follows:

“3. Verify **the Real Power and Reactive Power capability of** each existing applicable Facility at a periodicity not to exceed ten years from **the date(s) of** the last verification**(s) performed per R1.1, R1.2, R2.1, or R2.2**.”

With respect to Attachment 1, Section II, Item 5:

Given the language presently included in Section II, Item 5, it seems that entities may opt to conduct an engineering analysis that is based only on stated assumptions to determine the facility capabilities it will declare. It appears that the inputs to this analysis may be only design and operating limits information, but there does not appear to be any requirement for the analysis to examine or validate assumptions against recent operational realities for the equipment in question.

OPG contends that any engineering analysis should be based *at least in part* on recent equipment performance data (from operation or staged testing), and should not rely exclusively on design data – which may be considered unchanged since the previous verification (10 years prior), in which case there would be little value in conducting a new analysis with the same information as used in the prior verification.

Specifically, OPG expects that there should be some requirement to verify recent equipment performance is consistent with the assumptions used to develop capability curves (e.g., steady-state temperature rise on stator and field windings are as expected in particular operating conditions, validating use of 'design' field current and stator current limits to draw capability curves).

With respect to Attachment 1, Section II, Item 6:

OPG recommends removing the phrase "provided by the equipment manufacturer" from the end of 6.1, as follows:

"6.1. The generator steady-state Real Power and Reactive Power capability curve, or the synchronous condenser steady-state Reactive Power capability curve, ***provided by the equipment manufacture****r*"

This phrase is unnecessarily restrictive, as OEM capability curves are not always available and, in some cases, the manufacturer no longer exists. Additionally, some utilities produce their own capability curves, while others rely on third party consultants to produce them. The mention of the 'manufacturer' should be removed from 6.2 as well.

This phrase is unnecessarily restrictive, as OEM capability curves are not always available and, in some cases, the manufacturer no longer exists. Additionally, some utilities produce their own capability curves, while others rely on third party consultants to produce them. The mention of the 'manufacturer' should be removed from 6.2 as well.

OPG recommends adding to the list of explicitly mentioned examples of operating conditions that can dictate the power capability, "head water level" in 6.1.2, as follows:

"6.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, **head water level**, ambient temperature, or other conditions."

This recommendation to add an explicit mention of 'head water level' also applies to Item 7.1.2.

OPG notes that there are cases where the loss-of-excitation protection will be the first limit encountered in the under-excited operating region (this is common for hydro units with no UEL and a mho-based loss-of-excitation relay with a reach of more than 1.0 p.u., such that its characteristic is inside the limits of the stator MVA circle in the under-excited region).

As such, OPG recommends adding "in-service protective functions" to the list of equipment that is to be drawn on the composite capability curve, and suggests that this new point become 6.2, as follows (also showing the suggested removal of the word' "manufacturer's" with regards to the capability curve):

"…

6.2. In-service protective functions, if more restrictive than the equipment's capability curve, at nominal voltage of 1.0. per unit;

6.**3**. Excitation limiters, if more restrictive than the equipment**'s manufacturer's** capability curve, at nominal voltage 1.0 per unit;

6.**4**. **I**dentification of any Real Power or Reactive Power operational limitations1, if applicable;

…"

With respect to Attachment 1, Section II, Item 7:

The same recommendation to add an explicit mention of 'head water level' as made for 6.1.2 also applies to Item 7.1.2.

With respect to Attachment 1, Section III, Item 2:

In the following sentence, the reference to Item 4 appears to be in error – referring to Item 3 (which is where the simplified one-line is required) would make more sense:

“Refer to the associated labels depicted in the one-line diagram created in Section II, **Item 3***Item 4*.”

With respect to Attachment 1, Section III, Item 3:

“Staged testing or operating conditions **should be maintained constant for a sufficient time** in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.”

OPG agrees with this statement. However, it lacks clarity, and is subject to interpretation. What is ‘sufficient’?

For example, one person may refer to industry standards, such as the following from Section 7 of IEEE 115 (2019 version), which pertains to the test duration during ‘temperature testing’ in which a generator’s thermal capability is determined:

"Continuous loading tests should be continued until machine temperatures have become constant within ± 2 °C of the rise value for three consecutive half-hourly readings. If the coolant temperature is not constant, the test may be terminated when the temperature rise, based on at least three consecutive half-hourly readings, does not exceed the maximum previously observed rise. Continue the test if the coolant temperature for three half-hourly readings varies by more than 2 °C."

Someone else may believe that having held the loading point for 5 minutes is 'sufficient'.

It is not clear if this is just guidance, or if it is intended to be an enforceable requirement. The use of the word ‘should’ implies it is optional. If this is intended to be mandatory, then a more concrete, measurable criteria should be provided. It is unlikely that utilities will spend any more time than is necessary at test conditions that they would not otherwise be at, without a definite requirement to do so.

It would seem that the existing requirement to operate to the first over-excited limit at full-load (even if the first limit is a system-imposed voltage limit) would meet the intent of this statement. Perhaps this requirement should be retained or recommended as a best practice.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Att. 1, Section 1:

New unit verification due date should stay at 1 cal year after COD. 180 days is too tight of a schedule. Propose a reword of “Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating” as this may lead to confusion. “Nameplate” changes are rare and reflect some sort of machine upgrade, stator rewind, etc. Possible alternative is “by more than 10 percent increase or decrease of previously reported real or reactive power capability.”

Rather than using the proposed unit in outage verification plan, we suggest this alternative method for handling these cases:

“Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date deadline and has not had its capability verified within the past ten years.”

Att.1 Section II:

Given the quantity of the number of individual units, including the modeling of individual units in this category is impractical and unreasonable. We suggest removing that part along with the unreasonable modeling expectations of a TP.

The “final” qualifier on final PQ curve is undefined.

Att 1 Section II.3.1. Propose facility one-line not be so prescriptive in auxiliary equipment that has to be represented. The one-line should include GSU, generator, and auxiliary equipment information as needed by the Transmission Planner. As worded, the standard would imply all station service loads at all voltage levels need to be shown on the one-line.

Att 1 Section II.6-8. Strongly recommend removing requirement to create a composite capability curve (CCC). Transmission Planner has sufficient modeling information with Q Max & Q Min @ Pmin + Q Max & Q Min @ Pmax. A CCC will be tedious and time consuming for GOs/TOs to create and provide little benefit to a TP. The TP cannot input the CCC into their modeling software directly, and the data it provides is redundant with the data required by Att 2 Section III.

Att. 1, Section III:

What is the benefit of staged testing if it must be coupled with engineering analysis anyway?

Att. 1, Section III, Item 5 is problematic as some IBR facilities are requested by the TOP to operate in control modes other than voltage control (PF, e.g.)

For the part "*Not all data points outlined in items 6, 7, 8, or 9 need to be recorded if multiple methods are used. (1)":* This is very confusing because when either staged testing or operational data is used, engineering analysis is also required by the method options, and the analysis that must be done includes part of that identified in method option for engineering review – so this results in some points not being required to be recorded – which points?

For the part "*Record data on form in Att. 3 or in a form with equivalent info included. (2)*":

Att. 3 information needs to be part of this section, and not separated. The standard requirements include Att. 1 and Att. 2, but not Att. 3. This section is the only reference to Att. 3. Rather than reference a new section, just include the info in here.

For the part "*Maintain constant operating conditions during staged testing. (3)*":

How long is “for a sufficient time”?

For the part "*All aux eq in normal operation condition. (4)*"

Wording of (4) is incorrect – not all aux equipment is always in service during normal operations.

Att 2 Introduction. Recommend “Documentation showing the engineering basis and verification methodology” should be created by GOs/TOs and left on file if requested by TP. Recommend not making it a mandatory submission to the TP.

Att 2 Section II. See comments on Att 1 Section II.6-8. CCC should not be a requirement of engineering analysis.

Att 2 Section III. PQ data table should not have rows beyond Pmin and Pmax. Data in between Pmin and Pmax can be reasonably interpolated by TP if required.

For the part "*Changes may be made to this form provided that all info identified in Att. 1 in reported.*":

This statement is illogical since Att. 1 prescribes one line diagrams and CCCs. In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group. In addition to these comments, Southern Company supports the comments submitted by the NAGF. In addition to these comments, Southern Company supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Recommend changing the Standard to include a Capacity Factor Exception similar to MOD-026 and MOD-027.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	

Comment	
Attachment 1, Section 1, Page 12 of 22 reads: "Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days." Consider whether the intended target criteria of the nameplate rating by more than a 10 % increase or decrease requires revision/reconsideration if prime mover (turbine) upgrades result in an increase in generator electrical power.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No

Document Name	
Comment	

No. See the responses to questions 1 and 3.

Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	
Comment	

RF recommends against allowing any option that avoids the use of capability testing or operational data altogether. RF recommends the “engineering review” option under MOD-025-3 Attachment 1 Section II verification specification 5 be required in conjunction with the existing requirement to perform capability testing or to verify capability using operational data. Engineering review should be performed to adjust recorded values to account for limitations encountered during testing or operations that do not reflect the true capability of the units, but capability testing or operational data should still be used to ensure unexpected limiting factors are identified. For additional context to support RF’s recommendation, reference Project Scope 4 and 6 from the publicly posted SAR as well as the Recommendation section of the publicly posted Power Plant Model Verification Task Force White Paper on MOD-025 Testing.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

While the supporting materials and attachments provided for GOs aligns with Requirement R1, the referenced attachments provided for Facilities identified in 4.2.4 and 4.2.5 do not similarly align. To address this concern, additional attachments should be included that address Facilities identified in 4.2.4 and 4.2.5. (See our comments in response to Question 2 above).

Attachment 1

Section 1 (Periodicity of Verification)

Parts 2, 4 & 5: We also do not agree with the 12 month verification timeframe should be reduced to 180 days. (See our comments to Questions 1 and 2 above)

Section 2 (Verification specifications for applicable Facilities)

Part 5: Bullet 1 appears to duplicate obligations identified in PRC-019, Attachment 1, Part A (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function). If this is incorrect, please explain how a violation under MOD-025, Section 2, Part 5 would not also result in a violation of PRC-019, Attachment 1, Part A. (See our response to Question 9 below)

Section 3 (Staged test and operational data specification)

Part 9: EEI suggests that Part 9 be modified to the following in order to address the practicalities of testing variable generating resources (added text in boldface below):

9. For variable generating resources, such as wind, solar, or run-of-river hydro, and non-variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. **Staged testing or operational data shall be recorded from a time period when the Facility output of Real Power is forecasted to be greater than 75% of the Facilities nameplate total Real Power capability.** If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s)the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data.

9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Coproration (BHP) agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

Attachment #1:

Section 1, Item 1: The NAGF requested that the proposed language be modified to state that the verification date represents the engineering analysis completion date rather than the testing date.

Section 1, Item 5: Recommend revising the proposed language to remove “of 180 calendar days or more”.

Section 2, Item 2: The statement “considering applicable modeling expectations of the respective Transmission Planner” is vague and needs clarity or removal. Where will such expectations be defined?

Section 2, Item 5, First Bullet: The NAGF proposes removing this bullet as a review of all real/reactive information is not necessary prior to testing. All one needs to do is check the OEL and UEL curves in the PRC-019 study. No new information needs to be developed before performing MOD-025 tests. In addition, what is the difference between an engineering review verses engineering analysis?

Section 2, Item 5, Third Bullet: What are the criteria associated with operational data?

Section 2, Items 6 and 7: The NAGF notes that these items should not be required if Transmission Planners are not required to accept and use such data.

Section 3, Item 5: NAGF notes that some IBR facilities operate only in VAR or PF control modes.

Section 3 Items 6.3, 6.4, 8, and 9: It seems that Items 6.3 and 6.4 conflict with Items 8 and 9. Recommend that Item 6 be revised to recognize exemptions for Items 8/9.

Section 3, Item 8: The last sentence “If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.” Seems to conflict with the first two sentences of Item 8.

Attachment #2:

Figure 2 - Example Composite Capability Curve for IBR Facility: This seems to be a capability curve of a single inverter, not the composite curve of an IBR facility. Should this example be a composite capability curve at the point of aggregation of 75MW?

Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.

Answer	No
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI and believes the period provided for verification should remain at 12 months.

With respect to Attachment 1, PGE would like to request guidance for situations where equipment manufacturer curves are unavailable or if revised ratings have been established by heat run tests. Also, the base value may be a nominal value or equipment (base) rate value. For the purposes of the per unit references, PGE would like to see the reference base value defined.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

Please see the MRO NSRF's comments in question one and three.

Attachment 1, Section I, #2--We disagree with shortening the verification of a new facility from 12 months to 180 days. A new facility, such as a wind farm, may not have the ability to be at full capacity when the farm is new.

Attachment 1, Section II, #5--We believe that examples of an engineering review should be included to provide guidance. Attachment 1, Section III, #2--Provide an example of clarification of and engineering analysis to provide guidance. Attachment 3 Page 22--the addition of Transformer Impedance overlaps with VAR-002, R5 and is unnecessary since this is already required in other standards.

For variable generating resources, such as wind, solar, or run-of-river hydro, and non[1]variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line.   Staged testing or operational data shall be recorded from a time period when the Facility output of Real Power is forecasted to be greater than 75% of the Facilities nameplate total Real Power capability or at Real Power capability that allows the GO to demonstrate its full Reactive Power capability. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s)the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data. 9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached; 9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Attachment 1

Section I. Peridocity of verification

Recommend keeping existing points 2 and 4, consider deleting the rest, and consider adding event driven verification.

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be reverified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

{C}1.   {C}Verify each new applicable Facility within 12 calendar months of its commercial operation date.

{C}2.	{C}Verify an existing applicable Facility within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 12 calendar months.

{C}3.	{C}Verify an existing applicable Facility within 12 calendar months of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Section II. Verfication for applicable Facilties

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3.

Suggested edit:

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability with all equipment expected to be in-service for normal operation. *The requirements listed in the last sentence add cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.*

Attachment 2

Recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability

Likes 0	
Dislikes 0	

Response

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1

Answer	No
Document Name	

Comment

Attachment 1 – Section II verification indicates a GO does not have to test a facility and can rely on engineering data to calculate/provide the plant capabilities.SDG&E does not support the use of engineering reviews only to verify the Facility capability for all equipment expected to be in-service during normal operations. While this data is manufacturer-provided and may be dependable, plant parameters will inevitably change following years of operations and that will in-turn impact plant capabilities. The staged testing or operational data validation should be used instead of the exclusive proposed engineering review. The engineering review should only be allowed if the staged testing or operational data validation is unsuccessful in demonstrating the full capability of the facility because of restrictive transmission system conditions.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	

- It is not clear why data is required to be obtained within a 365 window, when the verification takes place on a 10-year cycle. It is recommended that the 365 day range be extended.
- Regarding verification specification 7.1.1: It is rare for the 100 kV and above system to run at 1.0p.u. It is recommended to use a voltage more reflective of normal operating voltage instead.
- Regarding verification specification 9, wording clarification is needed: "staged testing or operational data should be recorded with at least 90 percent of the inverters/generators *normal operating real power* at a Facility on-line"
- Regarding Attachment 2, Section I, Figure 1 and the untitled single-line diagram: The single-line diagram states, "The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above." It is recommended that the the composite capability curve be provided at point A in the single-line diagram (the inverter or synchronous generator terminal), since that is the closest representation to powerflow simulation models. Otherwise we will need to know the losses between the point of measurement and point A for each datapoint in the curve.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The additional requirements appear to overlap with PRC-019 and MOD-026 data. The additional engineering analysis adds significant financial burden to an entity with a large generation fleet and does not add a significant value for the Transmission Planner.

Attachment 1, Section I, Item #3 requires a periodicity of "ten years from the last verification date". We suggest this be changed to "ten calendar years" for consistency with other time delineations used in the standard.

Attachment 1, Section I, Item #2 requires verifying new facilities "within 180 calendar days" of their commercial operation date. However, MOD-025-2 allows for 12 calendar months. We suggest that bullet #2 be changed to "…within 12 calendar months of its commercial operation date". This allows the Generator Owners and Transmission Owners that have been subject to MOD-025-2 to maintain procedural / controls practices related to this timing requirement in place. This also allows more time for post commercial operation date break in and staging the logistics associated with verifications across more operating seasons.

Attachment 1, Section I, Item #4 requires verifying changed facilities "within 180 calendar days" of discovering a change that affects Real or Reactive Power capability by more than ten percent. However, MOD-025-2 allows for 12 calendar months. We suggest that Item #4 be changed to "…within 12 calendar months..". This allows the Generator Owners and Transmission Owners that have been subject to MOD-025-2 to maintain procedural / controls practices related to this timing requirement in place. This also allows for planning and staging the logistics associated with verifications across more operating seasons.

Attachment 1, Section I, Item #5 requires verifying returned-to-service facilities "within 180 calendar days of its return to service date" if it has been in outage for 180 calendar days or more which overlaps its scheduled verification date and has not had its capability verified within the past ten years. However, MOD-025-2 allows for 12 calendar months "for units that have been in long term shut down and have not been tested for more than five years". Despite the best plans and intentions, existing units may go into an unplanned outage state as their required verification periodicity date is approached. We suggest Item #5 be combined with Item #3 as follows:

3. *Verify each existing applicable Facility at a periodicity not to exceed ten calendar years from the last verification date. If an existing applicable Facility has an unplanned outage period which overlaps its ten calendar year verification date (preventing a verification within ten calendar years), complete the verification within 12 calendar months of its return to service date.*

Attachment 1, Section II, Item #6.1 requires a capability curve provided by the manufacturer. Many of the manufacturers of older units are out of business and the curves may not be available. We suggest removing this stipulation or, at least, allow the GO or TO to provide a curve that they have created.

The last sentence of Attachment 1, Section III, Item #8 (i.e. "If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.") makes no sense. If the minimum and maximum Real Power output are "equal" as stated in the first sentence, wouldn't this be the same?

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA suggests moving the engineering review method last and adding language to give preference to staged testing or operational data, such as the following:

The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8.

- *Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or*
- *Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability.*
- *If staged testing or operational data are* ***impractical****, perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations.*

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1,5

Answer	No

Document Name	

Comment

LCRA suggests moving the engineering review method last and adding language to give preference to staged testing or operational data, such as the following:

The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8.

- Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or
- Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability.
- If staged testing or operational data are **impractical**, perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	No
Document Name	

Comment

The changes to this standard are quite extensive and we appreciate the large amount of time and effort that the SDT put into making meaningful updates. However, we do not believe that 180 calendar days is a sufficient amount of time to complete the staged testing and engineering analysis for new applicable Facilities identified in Attachment 1, Section I, Item 2. As new facilities will be unlikely to have sufficient operational data for the purposes of MOD-025 verification, we recommend that this section be reverted to the previous value of 12 calendar months.

Furthermore, in Attachment 1, Section I, Item 5, the outage duration must be >= 180 calendar days AND overlap the scheduled verification date in order to be allowed to perform the verification within 180 calendar days of the Return to Service (RTS) date. Consider the following scenario showing why a defined outage timeframe could be an issue (Note: all dates and timeframes are completely arbitrary and for illustrative purposes only):

- Entity XYZ is the registered GO for Unit X.
- Unit X is a 100 MW Combustion Turbine (CT) that was last verified 9 years, 7 months ago per MOD-025-3.
- Unit X is scheduled to begin a 90-day hot gas path outage in 2 weeks (i.e. 9 years, 7 months, 14 days since last verification date).
- Due to the extensive nature of these types of outages and the massive quantity of worn-out components being replaced with new like-in-kind components, the unit capability will increase following the outage; however, the increase will likely be < 10%.
- Therefore, in order to provide the TP with the most accurate data, the GO plans to perform the MOD-025 verification with the new components installed immediately post RTS (i.e. within the 10-year verification period).
- Based on the currently scheduled dates, this plan leaves plenty of margin to complete the MOD-025 verification in a timely manner.
- During the outage, a major issue is discovered requiring extensive rotor work on the CT.
- These rotor repairs extend the length of the outage by an additional 51 days for a total outage time of 141 calendar days.
- As the extended outage time is < 180 days, Entity XYZ is now in violation of MOD-025-3 due to not performing the verification within the 10-year period.

- Example schedule:
- Last date of verification: 08/31/2013
- MOD-025-3 Verification Deadline per R1: 08/31/2023
- Outage Start Date: 04/14/2023
- Projected Outage End Date: 07/13/2023
- Actual Outage End Date: 09/02/2023

In the Scenario above, the GO is left with 3 possible choices. Either A) perform the verification prior to the scheduled outage or B) risk a violation if the outage gets extended or C) to extend the outage >= 180 days. In our opinion, none of the above choices are optimal. Please consider the following options for modifying the verbiage in Item 5.

Option A)

“Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years.”

Option B)

“Verify an existing applicable Facility prior to its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years.”

Note: Option A is the preferred option.

Additionally we had a member recommend keeping existing points 2 and 4, delete the rest, and add event driven verification. With the following comments:

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be re-verified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

1. Verify each new applicable Facility within 180 calendar days of its commercial operation date.
2. Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days.
3. Verify an existing applicable Facility within 180 calendar days of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Section II. Verification for applicable Faculties

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a “Net” Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3(No, it gives all the information required for either method to the TP)

Suggested edit:

The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability with all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used, as applicable to create the Facility capability curve under Section II, Items 6-8.

Attachment 2

Mildly recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Strongly recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
MP supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
The only portion we agree with is 10-year testing intervals. Any necessary data, that TPs will actually use, can be shown on capability curves and protection settings which can be provided in PRC-019.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
1. The only portion we agree with is 10-year testing intervals. Any necessary data, that TPs will actually use, can be shown on capability curves and protection settings which can be provided in PRC-019.	

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

Attachment 1, Section I, #2--We disagree with shortening the verification of a new facility from 12 months to 180 days. A new facility, such as a wind farm, may not have the ability to be at full capacity when the farm is new.

Attachment 1, Section II, #5--We believe that examples of an engineering review should be included to provide guidance. Attachment 1, Section III, #2--Provide an example of clarification of and engineering analysis to provide guidance. Attachment 3 Page 22--the addition of Transformer Impedance overlaps with VAR-002, R5 and is unnecessary since this is already required in other standards.

For variable generating resources, such as wind, solar, or run-of-river hydro, and non[1]variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line.   Staged testing or operational data shall be recorded from a time period when the Facility output of Real Power is forecasted to be greater than 75% of the Facilities nameplate total Real Power capability or at Real Power capability that allows the GO to demonstrate its full Reactive Power capability. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s)the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data. 9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached; 9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Attachment 1

Section I. Peridocity of verification

Recommend keeping existing points 2 and 4, consider deleting the rest, and consider adding event driven verification.

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be reverified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

Verify each new applicable Facility within 12 calendar months of its commercial operation date.

Verify an existing applicable Facility within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 12 calendar months.

3.   Verify an existing applicable Facility within 12 calendar months of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Section II. Verfication for applicable Facilties

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3.

Suggested edit:

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability with all equipment expected to be in-service for normal operation. *The requirements listed in the last sentence add cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.*

Attachment 2

Recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	No
Document Name	

Comment

In Attachment 1, Section II, it is stated that proposed option to utilize engineering review to verify the Facility capability for all equipment expected to be in-service for normal operation shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve. The engineering review is described as reviewing of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations, which includes the ambiguous term "but not limited to." This could e.g., include the design of the auxiliary power system and its coordination with the generator terminal voltage. It is recommended to provide additional specificity or refer to supporting documents on how engineering review could be performed to ensure consistency in results. Should the term 'Facility capability curve' in Section I, Item 5 be replaced with the term 'composite capability curve.' Further, since the capability curve is representing operational limits in Real (MW) and Reactive (Mvar) Power, it is recommended to document (discuss) their voltage dependency and the relation between current limiters, including armature current limiters, (in A) and the composite capability curve in MW/Mvar.

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	Yes

Document Name	
Comment	
Section II, SIGE would request further clarification on 7.5 and 8.5, “based on the least restrictive seasonal or operating conditions.”	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Following the point 4 of MOD-025-3 Attachment 1, please clarify if a temporary limitation or restriction in facilities can be considered as a change that affects its Real Power or Reactive Power capability. If the transmission planner doesn't need the Real Power and Reactive Power capability for a facility with a temporary limitation or restriction for a period higher than 180 days, can the verification be delayed until the corrections or adjustments?	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Tacoma Power agrees with language in Attachment 1, but as noted in the comments to Question 1, the Attachment 1 language should be moved into Requirement 1, as it provides further clarification/definition of the Requirement.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has no comment on this modification.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	

The only portion we agree with is 10-year testing intervals. Any necessary data, that TPs will actually use, can be shown on capability curves and protection settings which can be provided in PRC-019.

Likes 0	
Dislikes 0	

Response

6. The SDT believes the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

1. The SDT has not provided a cost estimate nor a cost/benefit analysis. No further standards should be developed if this vital budgeting and benefit information is not provided to impacted registered entities and vetted by industry. Regardless, based on our past experience MOD-025 compliance costs and administrative labor burden is excessive and without benefit to anyone. The standard has not and will never improve reliability.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

The SDT has not provided a cost estimate nor a cost/benefit analysis. No further standards should be developed if this vital budgeting and benefit information is not provided to impacted registered entities and vetted by industry. Regardless, based on our past experience MOD-025 compliance costs and administrative labor burden is excessive and without benefit to anyone. The standard has not and will never improve reliability.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The additional engineering analysis adds significant financial burden to an entity with a large generation fleet and does not add a significant value for the Transmission Planner.

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
• The SAR makes reference to the need to produce data that can be used ty the TP and PC and for the need for these two entities to verify data, however, the PC is not added as a recipient of the data in the proposed standard. • Item 2 in the Project Scope section is not addressed in the proposed revision. That item seems to already be provided for in MOD-032. • It is not clear how this proposed standard revision aligns MOD-025 with MOD-032 as stated in #7 in the Project Scope section. The proposal does not include data being provided to the PC as is provided for in MOD-032.	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question one and three.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	

Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
No. See the responses to questions 1 and 3.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company does not agree. All three of the proposed methodologies included in the Sep 2022 draft revision of MOD-025 will result in substantial costs related to the testing, reviewing, analyzing, and reporting. The benefit to the transmission planning group's ability to improve the quality of the modeling performed is not guaranteed. There is no obligation for any use of the verification reports. The reports may or may not be 100% accurate in predicting each and every corner of the composite capability curve. As the benefit of the results of this great amount of work is uncertain, yet the definite cost involved in delivering a capability report for tens of thousands of applicable facilities, the benefit to cost ratio of this	

proposition is very low. We suggest that the transmission planning groups utilize the data request ability currently housed in MOD-032 to directly request specifically what information they believe will best enable them to perform the modeling of interest.

In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group.

In addition to these comments, Southern Company supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	No
Document Name	

Comment

Submitted MOD-025 test reports to date have not been reviewed or used by the TPs or ISOs. Generator Owners have consistently seen this in different regions. ISOs mandate their own criteria for capability testing, rendering the standard ineffective. The drafting team should research the different ISO capability test requirements and establish a common method to determine Real and Reactive Power capability or remove MOD-025.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

See our responses to Questions 1 and 2 for suggested improvements.

Submitted on behalf of Exelon, Segments 1, 3

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We disagree with the proposed requirement and testing methods.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
These studies are expensive to conduct and adding requirements will only increase the costs.	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
The information required for MOD-025 is being provided by PRC-019.	
Likes 0	
Dislikes 0	
Response	

Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No

Document Name	
Comment	

Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	No
Document Name	
Comment	

Constellation believes that these changes will be extremely cost burdensome to the Generator Owner due to the change to the forms and required data that needs to be collected and documented, condensed time frame to provide data to the Transmission Planner, condensed timeframe for data to be provided and potential need to hire external resources (contractors) to meet the additional data prescribed. In addition, as previously mentioned in the response to other questions above, this new draft does not change any of the existing testing periodicities or data currently imposed by the Transmission Planners.

Alison Mackellar on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	No
Document Name	
Comment	

Constellation believes that these changes will be extremely cost burdensome to the Generator Owner due to the change to the forms and required data that needs to be collected and documented, condensed time frame to provide data to the Transmission Planner, condensed timeframe for data to be provided and potential need to hire external resources (contractors) to meet the additional data prescribed. In addition, as previously mentioned in the response to other questions above, this new draft does not change any of the existing testing periodicities or data currently imposed by the Transmission Planners.

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	

Comment

AZPS generally agrees that the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. However, AZPS does not agree that the proposed implementation plan related to MOD-025-3 is cost effective as it excellerates the periodicity time frames currently established under MOD-025-2 which will result in additional verifications within the first three years.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment

Please see the MRO NSRF's comments in question one and three.

Likes 0	

Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
As described in Q1 response, the data collected and its use does not justify the cost of testing or documentation creation/retention.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
At this time PG&E cannot determine if the modifications are cost effective.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by the NAGF.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The proposed changes will require significant specialized himan resources that are not readily available. Adopting the proposals made in the EEI comments for the other questions could assist in reducing the resources necessary.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The cost-effectiveness of MOD-025-3 will be zero if TPs declare for R3 that corrected test results cause no concern, then use as-tested data in their models, ref. our response to question #1 above.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Please see the responses to questions 1 and 3. The verification process described in these attachements puts un-nesessary burden on Generator Owner, Transmission Owner and Transmission Planner, which is detrimental to system reliability. The verification process should be simplified and adding more description to the process may not translate to more accuracy in the modeling. It significantly increases compliance costs with minimum improvement in reliability. The proposed verification process requires significant time, expertise, and difficulty in obtaining some of the required information for the older plant (which may increase the risk of non-compliance). It most likely will put a lot of burden on the Generation and Transmission Owners in preparing these documentations and analysis, while the effort of planners reviewing these documentations may not address their concerns and these documentations may not be used by planners for modeling purposes.	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until we have clarification, FirstEnergy cannot determine the cost-effectiveness of MOD-025-3.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
The SDT has not provided a cost estimate nor a cost/benefit analysis. No further standards should be developed if this vital budgeting and benefit information is not provided to impacted registered entities and vetted by industry. Regardless, based on our past experience MOD-025 compliance costs and administrative labor burden is excessive and without benefit to anyone. The standard has not and will never improve reliability.	
Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	
Cost efficiency will be impactted by whethter implementation plan requires reverificaiton for facilities that have been verified within the prior five years by the effective date of the standard. Facilities that have been verified, within the last 5 years should not need to be compliant with version 3 until the next verification date required under current version 2.	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Black Hills Coproration (BHP) will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black HIlls Corporation (BHP) will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	

Document Name	
Comment	
BHC will not respond to the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No response	
Likes 0	
Dislikes 0	
Response	

7. The SDT proposes a 1-year implementation plan for MOD-025-3 Requirements R3 and R4, with an additional 2 years (3 years total) for compliance with Requirements R1 and R2. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

Until we have clarification, FirstEnergy cannot support the proposed implementation plans.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

As the verification periodicity proposed for MOD-025-3 Requirements R1 and R2 is 10 yeares, a 10-year implementation plan that allows testing to occur over the normal 10-year timeframe is suggested. Otherwise 10 years of testing have to be compressed into 2 years. A 10-year implementation plan will also allow Generator Owner and Transmission Owner to combine the MOD-025, MOD-026 and MOD-027 testing because the collected data was similar to MOD-026 and MOD-027.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

Given that Requirements R3 and R4 **explicitly** require each respective TP, GO, or TO to take action "in accordance with Requirements R1 or R2", it is our opinion that, it does not make sense to include a phased-in implementation in this plan. Our recommendation is to change the implementation plan so that Requirements R3 and R4 are pushed back to coincide with the proposed effective date for R1 and R2 per the 3-year implementation plan strategy provided by the SDT	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Implementation should occur only after the great majority of TPs have agreed to use the calculated results of MOD-025-3.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E does not support the proposed staged implementation plan.

PG&E supports the input provided by EEI for Q7 related to Requirement R1 and R2 and that all Requirements for MOD-025-3 should become effective at the same time – 3 years after approval of the Standard.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

We believe 3 years may not be an adequate amount of time to conduct new staged tests for all of our BES facilities. We have completed several MOD-025 tests in the last year but that data will be more than 365 days out by the time the standard is adopted and then effective.

We believe if we implemented the R1/R2 changes now and these would then be compliant as of the adoption date it would greatly decrease the effort to comply with the standard.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Please add clarification about testing units that will be due before the standard becomes effective. This may lead to a much shorter time frame in between the last test and the required testing upon the effective date of the standard (could be as short as 3 years).	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF has concerns that 66 months of testing could be compressed into 3 years as MOD-025-3 testing requires updated information and therefore retesting within 2 years. The MRO NSRF suggests a revised implementation plan that allows testing occur over the normal 10-year timeframe proposed by the drafting team.

The implementation plan needs to accept previous testing dates for NERC MOD-025-2.

While the MRO NSRF appreciates the MOD-025 testing period change to 10-years, due to the administrative nature of MOD-025, the MRO NSRF a 10-year implementation with milestones to spread the work out and to potentially avoid a crush of X-day deadlines reporting at the end of the implementation period.

The MRO NSRF notes the potential for double jeopardy between NERC standards MOD-025 and PRC-019 for the Over and Under Excitation Limit functions (OEL and UEL functions) and recommends the SDT ensure that double violations do not occur for a MOD-025 testing mistake or PRC-019 analysis.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS supports the following comments submitted by EEI on behalf of their members: EEI notes that MOD-025-2 already has a 5 year requirement that defines the periodicity of testing. Entities should not be obligated to accelerate testing under MOD-025-3 but should be allowed to cycle their first verification test for each resource in line with the existing MOD-025-2 cycle. In other words, Responsible Entities shall initially comply with all periodic requirements in MOD-025-3 within the periodic timeframes of their last performance under MOD-025-2.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment	
The initial implementation for real and reactive testing under MOD-025-2 provided an implementation timeframe of five (5) years to complete initial testing across an entire fleet of generating units (based on NERC registration). Due to economic constraints and planned testing requirements, providing less than a five (5) year planning cycle is not an adequate amount of time. In addition, Question 7 describes the intent would be an additional two (2) years for R1 and R2 implementation, the implementation plan documentation is not as clear on this subject and states 24 months from the effective date which causes confusion on the expectation of required tests to be completed. Constellation suggests a language change and additional consideration be given to the implementation plan to a more reasonable three (3) years from the last test completion in order to allow scheduling a phased implementation and to lessen the economic impact to complete all tests on a large fleet of generating units in a short period of time. Kimberly Turco on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
The initial implementation for real and reactive testing under MOD-025-2 provided an implementation timeframe of five (5) years to complete initial testing across an entire fleet of generating units (based on NERC registration). Due to economic constraints and planned testing requirements, providing less than a five (5) year planning cycle is not an adequate amount of time. In addition, Question 7 describes the intent would be an additional two (2) years for R1 and R2 implementation, the implementation plan documentation is not as clear on this subject and states 24 months from the effective date which causes confusion on the expectation of required tests to be completed. Constellation suggests a language change and additional consideration be given to the implementation plan to a more reasonable three (3) years from the last test completion in order to allow scheduling a phased implementation and to lessen the economic impact to complete all tests on a large fleet of generating units in a short period of time. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	No
Document Name	

Comment

There is not a significant enough change regardless of the new inclusion of a composite capability curve to warrant a new implementation plan. Implementation should be based off the last verification.

Likes 0	
Dislikes 0	

Response

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese

Answer	No
Document Name	

Comment

Exelon agrees with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #7.

Likes 0	

Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Clarifications are needed before the proposed implementation plan can be supported.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We disagree with the proposed requirement and testing methods.	
Likes 0	
Dislikes 0	
Response	
Sheraz Majid - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Two year implementation plan may not be sufficient considering new applicability added to the Standard. Request clarification of FACTS devices, e.g. SVC that are already in service prior to the effective date of the standard. What would be the obligations for R1/R2 compliance.	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	

The implementation time periods for R1-R4 should all be within 3 years with the TP (or better “Planning Coordinator” or “Planning Authority”) deciding the submission deadlines for individual facilities. The deadlines for individual facilities would be spread such that they would occur between 18-36 months to allow the appropriate testing while recognizing the system limitations which will not allow all facilities to test at the same time. Facilities which have tested in the prior 2 years should not have to re-test until the MOD-025-3 cycle based on the date of the previous test. System reliability assessments require accurate facility reactive power capability information and 3 years should be enough time – especially if GOs and TOs begin planning for the testing now.

Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

The explicit inclusion of the new requirements R1 and R2 into the new R3 and R4 makes it difficult to achieve compliance with R3 and R4 in the first three years of implementation. Immediately integrating all the information from the GO and TO for submission for TP evaluation makes the phased in approach confusing for everyone involved.

Requiring simultaneous compliance for all four requirements would be easiest and cleanest as past phased-in approaches have been confusing.

It would be better to start enforcing this when the next MOD-025 cycle becomes effective for a given existing resource.

Likes 0	
Dislikes 0	
Response	

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	

The SRC proposes the SDT provide a graduated approach to implementation with completion milestones (e.g., 40%, 60%, 80%, 100%) to minimize impact to affected entities (*see* the Implementation Plan for **Project 2007-09: Generator Verification (MOD-025-2)**. At the same time, the SRC recommends extending the overall implementation schedule to align with the current five-year period instead of condensing it into a two-year period. Not adopting a milestone schedule could result in a significant influx of work near the end of the implementation period making it administratively burdensome to meet the 30-day, 90-day and 180-day response times and pull resources away from other, higher reliability needs to satisfy compliance documentation deadlines.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company believes that R3 and R4 are purely administrative in nature and will not improve the reliability of the BES. We suggest removing these requirements altogether.

Our understanding of the wording of this implementation plan gives the GO 2 years after approval of the standard to perform the initial real/reactive power engineering analysis of all units in scope. We believe this is not a sufficient window of time for such a large undertaking. Considering most standards requiring detailed analysis have a 5-year phase in period, we believe 5 years of phase-in should be the minimum time allotted. With zero credit given for the previous staged testing method of satisfying MOD-025, we suggest developing a revised implementation plan that allows a 10-year timeframe to achieve the initial round of capability verification.

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Three-years is not sufficient to perform all MOD-025-3 verifications for compliance with Requirements R1 and R2. Recommend a minimum of 5-calendar years total for compliance with Requirements R1 and R2, to at least be consistent with the original periodicity of MOD-025-2 through implementation. Agree with transitioning to a ten-year periodicity in MOD-025-3 after implementation.

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES Power Marketing.	
Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
No. PacifiCorp has concerns that 5 years of testing could be recompressed into 2 years as MOD-025-3 testing requires updated information and therefore retesting within 2 years. PacifiCorp suggests that revised updated testing occur over the 10-year timeframe proposed by the drafting team.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed staged implementation plan. Requirements 1 and 2 provide GOs and TOs three years before they are obligated to comply with these Requirement. However, these is no meaningful work that a TP could do under Requirement R3 until GOs and TOs have completed their verification testing and submittals under Requirement R1 and R2. Additionally, GOs and TOs will not receive any notifications of technical concern until after obligations under Requirement R1 and R2 are sent to the TP under Requirement R3, meaning no work can be done under R4 until R1, R2 and R3 tests, submissions, and reviews are completed. For this reason, all Requirements in MOD-025-3 should become effective at the same time (i.e., 3 years after approval of the Reliability Standard). EEI notes that MOD-025-2 already has a 5 year requirement that defines the periodicity of testing. While making MOD-025-3 effective 3 years after approval is acceptable, entities should not be obligated to accelerate testing under MOD-025-3 but should be allowed to cycle their first verification test for each resource in line with the existing MOD-025-2 cycle. In other words, Responsible Entities shall initially comply with all periodic requirements in MOD-025-3 within the periodic timeframes of their last performance under MOD-025-2.	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	No

Document Name	
Comment	
Black Hills Coproration (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
The MRO NSRF has concerns that 66 months of testing could be compressed into 3 years as MOD-025-3 testing requires updated information and therefore retesting within 2 years. The MRO NSRF suggests a revised implementation plan that allows testing occur over the normal 10-year timeframe proposed by the drafting team. The implementation plan needs to accept previous testing dates for NERC MOD-025-2. While the MRO NSRF appreciates the MOD-025 testing period change to 10-years, due to the administrative nature of MOD-025, the MRO NSRF a 10-year implementation with milestones to spread the work out and to potentially avoid a crush of X-day deadlines reporting at the end of the implementation period. The MRO NSRF notes the potential for double jeopardy between NERC standards MOD-025 and PRC-019 for the Over and Under Excitation Limit functions (OEL and UEL functions) and recommends the SDT ensure that double violations do not occur for a MOD-025 testing mistake or PRC-019 analysis.	
Likes 0	

Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Three years for Requirements R1 and R2 is probably sufficient for entities that own a smaller number of applicable Facilities. However, for entities that own a lot of applicable Facilities, three years isn't enough time to do them all. Also, many, if not most, generators don't have the engineering expertise in-house to perform the engineering reviews required by Attachment 1, Section II, Item #5. As such, an outside consultant/engineering firm will be required to be obtained to perform this work. As mentioned in the Implementation Plan, there are a limited number of vendors and SMEs in the industry so their availability will be limited. We recommend a phased implementation approach similar to that provided for MOD-025-2, with 10 years to achieve 100% compliance.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Given that Requirements R3 and R4 **explicitly** require each respective TP, GO, or TO to take action "in accordance with Requirements R1 or R2", it is our opinion that, it does not make sense to include a phased-in implementation in this plan. Our recommendation is to change the implementation plan so that Requirements R3 and R4 are pushed back to coincide with the proposed effective date for R1 and R2 per the 3-year implementation plan strategy provided by the SDT	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

MP supports EEI’s comments.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

1. No Comment

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NVE has concerns that 66 months of testing could be compressed into 3 years as MOD-025-3 testing requires updated information and therefore retesting within 2 years. The MRO NSRF suggests a revised implementation plan that allows testing occur over the normal 10-year timeframe proposed by the drafting team.

The implementation plan needs to accept previous testing dates for NERC MOD-025-2.

While NVE appreciates the MOD-025 testing period change to 10-years, due to the administrative nature of MOD-025, NVE a 10-year implementation with milestones to spread the work out and to potentially avoid a crush of X-day deadlines reporting at the end of the implementation period.

NVE notes the potential for double jeopardy between NERC standards MOD-025 and PRC-019 for the Over and Under Excitation Limit functions (OEL and UEL functions) and recommends the SDT ensure that double violations do not occur for a MOD-025 testing mistake or PRC-019 analysis.

Likes 0	
Dislikes 0	

Response

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE requests language such as “reoccurring periodicity from the date of previous coordination date of PRC-019-2 R1” in question 13 for MOD-025-3. For example, “reoccurring periodicity from the date of previous capability verification date of MOD-025-3 R1 and R2,” which could be inserted into the Implementation Plan under the Initial Performance of Periodic Requirements section. Alternatively if retesting is need, SIGE requests clarity that the test will have to be redone upon new implementation and this language added to the Initial Performance of Periodic Requirements.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed plans.	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC defers to the applicable entities to comment on the time needed to put processes, procedures, or technology in place to meet the proposed language.	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
The “Compliance Date for MOD-025-3 – Requirements R1 and R2” section of the draft Implementation Plan appears to leave a gap between the MOD-025-2 ineffective date and the MOD-025-3 R1 and R2 effective date. To provide more clarity, RF recommends adopting “Initial Performance of Requirement R1 and R2” language similar to that used in the Project 2007-06 Implementation Plan for PRC-027-1 R2. This would focus on “initial performance” of the first verifications under the new standard while making it clear that no gap is left between MOD-025-2 and MOD-025-3.	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

8. Provide any additional comments on MOD-025-3 and technical rationale document for the standard drafting team to consider, if desired.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
NVE does see value in change management testing and the 10-year testing to catch equipment limits. NVE asks for clarification on Attachment 1 Sections II and III. It appears the standard may not require physical testing if verficiation is completed via engineering review (effectively mirroring PRC-019).	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
Information obtained is not usable in real life; it is meaningless.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
Information obtained is not usable in real life; it is meaningless.	
Likes 0	
Dislikes 0	

Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
Information obtained is not usable in real life; it is meaningless.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is readily apparent from the considerable quantity of changes made to the previous version of MOD-025 that the SDT spent a copious amount of time and effort working on this revision. We would like to thank you for your hard work and for providing use with the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
Applicability in Section 4 of MOD-025 for dynamic reactive resources (identified through Inclusion I5) in Section 4.2.4 seems to differ from the wording in other Applicability sections in MOD-025 and PRC-019 by stating “but not limited to,” while the term ‘including’ is used in other Applicability descriptions. The wording ‘not limited to’ seems to indicate that there have to be more than those listed, while the ‘corresponding’ Applicability criteria in PRC-019 only lists synchronous condensers (see #14 below). It is recommended to align the text in in Section 4.2.4 of MOD-025 with other applicability statements. Further, Applicability Section 4.2.5 of MOD-025 is listing HVDC terminal equipment including: Voltage source converter as applicable. Is the wording ‘including’ necessary since seems to be the only case?	

Please consider updating Compliance Section C to include the abbreviation (CEA) for Compliance Enforcement Authority; and use the CEA abbreviation in Compliance section 1.2.	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	
Document Name	
Comment	
The MRO NSRF does see value in change management testing and the 10-year testing to catch equipment limits. The MRO NSRF asks for clarification on Attachment 1 Sections **II** and **III**. It appears the standard may not require physical testing if verficiation is completed via engineering review (effectively mirroring PRC-019).	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC Regional Standards Committee (RSC) supports the drafting team proposal on the project.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	

Portland General Electric Company supports the comments provided by EEI

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The NAGF has no additional comments.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Coproration (BHP) supports the comments as supplied by the EEI.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment

The inclusion/exclusion of Line Current Commutated (LCC) HVDC terminal equipment is unclear based on the use of “including” in Applicability Section 4.2.5. If the SDT intends “including” to mean “exclusively including,” RF recommends revising for clarity (either by rewording or by explicitly listing exclusions).

RF recommends explicitly defining whether “static reactive resources” such as shunt capacitors and shunt reactors are excluded by Applicability Section 4.2.4. The Facilities language on Technical Rational page 2 should also be updated to reflect whether static reactive resources are excluded (as it stands, the blanket reference to I5 would suggest inclusion).

Likes 0	
Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

PacifiCorp requests to keep the example that is included in section G (Reference). These examples are very much needed in that it not only shows what the standard is looking for but will help keep auditors from using personal bias. Issues during an audit can often stem from differences between the SME and the auditors. This difference can be drastically reduced by useful examples of what the standard is looking for.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Buckeye Power, Inc. - 5 - RF

Answer	
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES Power Marketing.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	
Comment	

Agreement with the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	
Document Name	
Comment	

In the Applicability section, we believe that it is best to explicitly specify what facilities are included rather that point to a document that can be changed outside of the reliability standard and affect the compliance scope of the functional entities who own the equipment. (don't make people have to collect information from other sources to understand what a particular standard is requiring)

This details on how to do the verification are not needed. Further, the standard as a whole should focus on what is to be done rather than how it is done (most of the attachments). The level of specification in this draft is overtly excessive. Consider limiting the extent of the specification to using prudent engineering judgement.

In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group.

In addition to these comments, Southern Company supports the comments submitted by EEI.

In addition to these comments, Southern Company supports the comments submitted by SERC Generator Working Group.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

MOD-025-3 allows for Hybrid methodology, as a combination of engineering analysis used together with Staged Data Testing or Existing Operational Data, to be used for compliance.

Can you please provide additional details regarding expected minimum values of the operational data and testing limits required to be attained for compliance in the case where hybrid methodology is being used to verify the Facility Capability of all the equipment expected to be in service for normal operation.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez

Answer	
Document Name	

Comment

MOD-025 needs to separate the requirements of synchronous generation vs other dispersed resources. With the growing volume of dispersed resources, it seems there needs to also include requirements for VAR control abilities. MOD-025 white paper also makes a statement about the data often not being suitable for planning studies. How do we know if we are doing the right testing and data collection?

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE appreciates the SDT’s efforts in revising standards to account for grid transformation and ensure reliability.

In the Facilities section 4.5 of proposed MOD-025-3, this standard says that it applies to resources/facilities that meet the BES Inclusions, but it does not mention the BES Exclusions. BES resources/facilities are determined by applying the Inclusions and then applying the Exclusions (for example, Exclusion E2). By only referring to the Inclusions in the facilities section, this standard could apply to some non-BES resources/facilities. Is this the intent of the SDT?

Texas RE recommends the following revisions to the Facilities section:

4.2.1 Individual generating resource identified through *the application Inclusion I2* of the BES definition.

4.2.2 Generating plant/Facility identified through *the application Inclusion I2* of the BES definition.

4.2.3 Generating plant/Facility of dispersed power producing resources identified through *the application Inclusion I4* of the BES definition.

4.2.4 Dynamic reactive devices identified through *the application Inclusion I5* of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to: 4.2.4.1 Synchronous condenser; and 4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

4.2.5 HVDC terminal equipment *identified through the application of the BES definition including*: 4.2.5.1 Voltage source converter (VSC).

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
Adequately performing this test requires for the Transmisson System to be at a voltage level for Reactive Power support. An additional requirement for the TO to respond to support request from the GO/resource owner would help in performing a staged test adequately.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Section 4.1 should include "4.1.4 Planning Coordinator / Planning Authority" Replacing "Transmission Planner" with "Planning Coordinator" or "Planning Authority" may be better for R1-R4 There are concerns that some of the particular features of off-shore wind generating facilities are not sufficiently captured by the proposed standard. For these generating facilities, there are often FACTS devices which are part of the overall generating facility but which can be located close to the transmission system interface or near or part of the wind turbine generator fleet. Additionally, some of these off-shore wind generating facilities have HVDC circuits connecting the wind farm to the shore. How these FACTS devices, HVDC terminals, and generators are to be considered/operated during tests is not at all clear. Also, how are static shunt reactors and capacitors connected behind a GO point-of-interconnection expected to be accounted for – or not? What if the generating facilities are owned by one entity and the AC or HVDC facilities are owned by a different entity?	
Likes 0	
Dislikes 0	
Response	
Sheraz Majid - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	

Request c
Likes 0
Dislikes 0
Response
David Jendras Sr - Ameren - Ameren Services - 3
Answer
Document Name
Comment
No Comments
Likes 0
Dislikes 0
Response
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3
Answer
Document Name
Comment
N/A
Likes 0
Dislikes 0
Response
Brian Lindsey - Entergy - 1
Answer
Document Name
Comment
No comment

Likes 0	
Dislikes 0	

Response

Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	
Document Name	

Comment
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	
Document Name	

Comment
No additional comments. Alison Mackellar on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	

Comment
No additional comments.

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

AZPS recommends that the VSL time frame requirements for Requirement 1, Attachment 1, Items 1, 2, 4, or 5 should be increase as the periodicity for verifying real and reactive power cability is 10 years. Given the relatively low reliability impact of any given generator's reactive power data, a time frame of 1 year would not have any significant reliability impact.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

The MRO NSRF does see value in change management testing and the 10-year testing to catch equipment limits.

The MRO NSRF asks for clarification on Attachment 1 Sections II and III. It appears the standard may not require physical testing if verification is completed via engineering review (effectively mirroring PRC-019).

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC supports the comments supplied by the EEI.	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
AES CE does not have additional comments.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has not additional comments	

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	
Document Name	

Comment

The SERC Generator Working Group wants to ensure that the transmission planner actually needs this data (for example, the PQ table). Would like justification for this as it will likely require the use of contractors and thus an additional cost.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro offers the following additional comments.

1. Parts 4.2.2 & 4.2.3 of Section 4.2 Facilities of this Draft 1 refer to Inclusions I2 & I4 of the BES Definition without mentioning any Exclusions. Exclusion E2 can override Inclusions I2 & I4. Therefore, the current language that does not account for Exclusion E2 may result in non-BES Facilities becoming subject to MOD-025-3 compliance. For example, if I2 applies to a facility, based on the current language, it will then be applicable to MOD-

025-3. However, E2 may also be applicable to the same facility thereby making that Facility non-BES. This way, you can end up with non-BES facilities that are applicable to MOD-025-3. If it is not the intention of the SDT that such non-BES facilities be applicable to MOD-025-3, the language under Sections 4.2.2 & 4.2.3 should be amended accordingly. Below is suggested wording:

"…Inclusion I2 of the BES definition (and Exclusion E2 is not applicable)…"

"…Inclusion I4 of the BES definition (and Exclusion E2 is not applicable)…"

2. Attachment 1 Section I – 3 requires verification at least every 10 years. The VSL table 120 calendar months. For consistency, BC Hydro recommends using the same terms in the Attachment and the VSL table, i.e. "calendar years" or "calendar months".

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	
Document Name	

Comment

The scheduling of NERC's outreaches to the electorate for Project 2021-01 illustrates our concerns about not having adequate opportunity for stakeholders to contribute their expertise to the development of standards. That is, MOD-025-3 and PRC-019-3 were posted for comments from 9/29/2022 through 11/14/2022, while balloting runs from 11/4/2022 through 11/14/2022. This overlap makes it impossible for feedback from the first exercise to be taken into account in the second one, making it seem as if commenting is merely a pro forma exercise.

The only opportunity for stakeholders to be heard then comes when casting a negative ballot, resulting in extra time and trouble for everyone. We suggest that draft standards be posted for industry comment, then the SDT should incorporate these inputs, then NERC should proceed to a vote..

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

Currently, FACTS devices are not defined in MOD-025, Technial Rationale, or the NERC Glossary of Terms. BPA recommends the drafting team revise the MOD-025 Technical Rationale document to include language that specifies/identifies what devices are included as part of FACTS devices.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments: It is readily apparent from the considerable quantity of changes made to the previous version of MOD-025 that the SDT spent a copious amount of time and effort working on this revision. We would like to thank you for your hard work and for providing use with the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
Technical rational page 5 section II, items 8, "for dynamic reactive resources (FACTS, HVDC, VSC)...," HVDC should be deleted. It is not a reactive resource.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy seeks clarification on devices to include FACTs and justification on the need for testing of these. SVCs and other FACTS devices we view as not having moving parts which should limit their change in output and response over time and we seek clarification of their inclusion.

Also, the proposed MOD-025 revision transforms what was formerly a "required testing verification of demonstrated capability" into some form of an engineering analysis justifying a theoretical capability curve. The standard needs to include a better definition of "Engineering review" or "engineering analysis" along with examples or prescribed methods of how this "engineering analysis" is to be conducted.

In addition, FirstEnergy does not understand how the proposed revision to MOD-025 for reactive testing will provide any additional or more accurate information to the transmission planning entities since we currently already submit most of the needed information.

Generator capability curves are submitted via the annual MOD-032 submittals to PJM. Analysis of over/under excitation limiters are already included in the required PRC-019 documentation.

The excerpt below comes from the summary section of the NERC white paper "Implementation of NERC Standard MOD-025-2"

"The PPMVTF believes that there is value in performing the staged verification tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing may not be directly usable to represent the actual capability of the machine in power system models, and that the tests do not generally accomplish the stated purpose of the standard.

Likes 0	
Dislikes 0	
Response	

Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

Kestrel notes the pervasive use of the term 'real' power. The terms 'real' and 'imaginary' refer to quantities within the mathematical tool (complex plane) which is used to quantify the orthogonal relationship between active and reactive power. Both active and reactive power are real (exist in physical reality) and neither is imaginary. Similarly, use of the term 'real' implies the opposite term (imaginary) exists. As such, Kestrel proposes to replace the term 'real power' with 'active power' in all instances.

Likes 0	
Dislikes 0	
Response	

9. Do you agree the language proposed in PRC-019-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
"Protective functions" would likely include embedded systems which infers an understanding of the decision trees and logical operators of every device in scope. This level of understanding may only be fully grasped by the manufacturers themselves, and may also include proprietary information that the OEMs may not wish to share. This puts the TO and GO at risk for having an understanding of the underlying logic that may be fully grasped or known only by the manufacturers themselves.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
1) MH agrees with the removal of stability limits, however, MH recommends further wording changes for R1 and to remove "equipment capabilities"as a requirement of the control and protection coordination. 2) MH agrees with that a coordination of control and protection elements should take place if equipment capabilities change and should be plottoted (if known) as part of Attachement 1; however, this particular standard should focus on the coordination between control and protection, not protecting the equipment. 3) MH would also like to have the standard reflect how to handle instances when the equipment capabilities are not known, such as voltz per hertz limitations for older generators? Clear definitions and operating ranges need to be provided for equipment capabilities in Appendix A.	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	

Comment

Footnote 3 appears to be creating a requirement to perform a coordination study A coordination study was not required before and should not be need to satisfy PRC-019. WECC recommends either removing footnote 3 or if the SDT is actually intending to require a protection system coordination study as part of PRC-019 then it should clearly be stated in the requirement.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The M1 statement, "Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-X Diagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, or other evidence," should become for the sake of clarity, Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as graphical representations of coordination (e.g. P-Q Diagram, R-X Diagram, Inverse Time Diagram), equivalent tables, the results of steady-state calculations or dynamic simulation studies, or other evidence." The word "including" is otherwise open to misinterpretation.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No

Document Name	
Comment	

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	
Comment	

BC Hydro appreciates the drafting team's efforts and the opportunity to review, and offers the following comments.

The Technical Rationale states that that FACTs devices, such as SVCs and STATCOMs are intended to be excluded. However, the Subsection 4.2.3 of Section 4 Applicability wording "dynamic reactive resources identified through Inclusion I5…" Dynamic reactive resource is not defined and may be subject to interpretation. BC Hydro recommends that this wording be revised for greater clarity within the Standards rather than just within the Technical Rationale; a viable alternative may be to add a clarifying footnote.

BC Hydro noted the revised language in Section 4.2.5 with respect to PRC-019-2 ("Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan"). BC Hydro's appreciates that this revision makes use of the NERC Glossary of Terms definition, and has the understanding that this revision is not intended to materially modify the applicability scope of current PRC-019-2. Please confirm whether this understanding is accurate.

Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	
Comment	

WEC Energy Group supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
The SERC Generator Working Group asks the question as to why this needs to be done every 5 or 6 years. Excitation systems don't change and are usually black boxes that require the use of vendors and/or contractors to update. We suggest 10 years to align with MOD-025	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E does not support the proposed language in Requirement R1. PG&E concurs with the input provided by EEI for Q9 on the reasons for not supporting the language and the addition of clarification language.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Coordination should be more specifically defined so that entities are able to achieve what the SDT is looking for. It is unclear what the SDT is expecting for coordination between the control functions and protective functions, as well as considering how the protective functions monitor different physical	

locations within a plant. Documentation on how to perform the coordination and what is expected must be developed in the industry before it is reasonable to expect entities to comply. Presently, this documentation does not exist.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	No
Document Name	

Comment

BHC agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The SDT should clarify "Facilities" for all NERC standards including PRC-019-3 and MOD-025-3. As written, Facilities could be individual BES generators rated at less than 1 MVA. The SDT should use the terms "BES plant" meaning:

• Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or

• Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

The MRO NSRF believes the requirements in PRC-019 and MOD-025 should be harmonized to once every 10-years.

R1.1.1 when coupled with Attachment 1, Paragraph A for synchronous machines makes it is quite clear that the intent is that a limiter must be coordinated with the associated protective functions of the same parameter. For example, a field over-excitation limiter would be coordinated with a field over-excitation trip but there would be no expectation to have a limiter of one parameter limit before the trip based on a different parameter. For example, it would not be necessary to show that the field over-excitation limiter would act to limit prior to the occurrence of a volts/hz trip. The wording of R1.2.1, R1.2.2, and Attachment 1, Paragraph B for IBR generating Facilities does not seem to include a stipulation that the control function need only be coordinated with the associated protective function for the given parameter. R1.2.1 only states that in-service power plant controller control functions occur before protective functions, R1.2.2 only states the in service control functions of the IBR units must be set to act before protective functions, and Attachment 1, Paragraph B is only a list of control, limiter, and protective function without any stipulation that control parameters only need be coordinated with the protective function of that same parameter. Example: R1.2.1 and R1.2.2 could be read to require that if a PQ limiter is applied in the PPC or on the IBR units, than the PQ limiter must be set to take action to limit before a trip were to occur for any parameter such as overvoltage of an individual IBR located at the extreme remote end of a collector under abnormal grid conditions and transients. Such an interpretation that any limiter must act before any protective function would result in limiters being set so tightly to avoid trips of remote IBRs in the collector system under extreme conditions but would greatly limit the reactive capability of the overall IBR generating facility to support the grid. Please add clarification to Attachment 1, Paragraph B that control functions only need to coordinated with protective functions of the same monitored parameter.

Information developed under PRC-019-3 supports entity compliance activities under MOD-025-3. Given the linkage between PRC-019 and MOD-025 compliance obligations under Requirement R1 should be harmonized. For this reason, GOs and TOs should be required to conduct coordination of generating unit or plant capabilities, voltage regulating controls and protection at a maximum of every 10 years, consistent with MOD-025-3.

The term “protection function” is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. The MRO NSRF suggests that footnote 4 be revised to reference the protective functions outlined in Attachment 1. An example might be:

• 4. A protective function includes an action performed by a Protection System device that **replicate the functions listed in Attachment 1**

Add language to Attachment 1, Paragraph B that clearly states that control functions only need to be coordinated with protective functions of the same monitored parameter.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

a) Information developed under PRC-019-3 supports entity compliance activities under MOD-025-3. Given the linkage between PRC-019 and MOD-025 compliance obligations under Requirement R1 should be harmonized. For this reason, GOs and TOs should be required to conduct coordination of generating unit or plant capabilities, voltage regulating controls and protection at a maximum of every 10 years, consistent with MOD-025-3.

b) The term "protection function" is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. We also understand that Project 2019-04 (Modifications to PRC-005-6) is considering how to define "protection functions" as it relates to inverter based resources. While both this SDT and the Project 2019-04 SDT have approval to add new glossary terms both should coordinate and align definitions.

c) Add language to Attachment 1, Paragraph B that clearly states that control functions only need to be coordinated with protective functions of the same monitored parameter.

Likes 0	
Dislikes 0	

Response

Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC

Answer	No
Document Name	

Comment

Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	No
Document Name	

Comment

The maximum timeframe should be aligned with MOD-025 verification. PRC-019 is not tied to maintenance of protective relays (PRC-005). No other issues with R1.1 or R1.2.

Likes 0	
Dislikes 0	

Response

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #9.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
The repetitive coordination adds no value when there are no changes of settings (demonstrated by setting documentation and review). These types of settings are not casually or frequently changed. The need for coordination updates is covered by R2, providing the mandate to demonstrate coordination when changes are implemented. Also, the original coordination frequency was consistent with the MOD-025 cycle because voltage controls directly impact capability testing. A 10-year frequency is consistent and rational with the basis for MOD-025 interval if an interval is mandated.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Section B, R1 1.2.1 & 1.2.3: This standard should not mix control and protection “coordination.” Control functions in Power Plant Controllers and IBR units are often proprietary and not always easily obtainable. Furthermore, the term “control functions” is a broad expression that will leave GOs/TOs susceptible to falling out of compliance on a subjective basis. Wording should be revised that if any limiters are programmed in these control devices, the equipment should limit before it trips.

The Attachment 1, section B list of IBR items incorrectlly characterizes the IBR phase lock loop circuit as a protective function. That is purely a control item - it relates directly to the ability to control the power conversion accomplished by the inverter. If that circuit is unable to accomplish its function the inverter is not control-able, and must stop the power convertion immediately through the cessation of the gate pulses which permit the conduction of current through the legs of the bridge. The Momentary cessation, too, is purely a control function which must be invoked when the power conversion is not controllable. There is no coordination to be coordinated between these items and the limiters and protection functions that are listed (over current, over voltage). We question the use of "IBR unit phase undervoltage *protection"* as the IBR phase undervoltage condition may trigger an uncontrollable power conversion condition, but is not at all related to any protection scheme which needs to be used.

R1: Because the coordination of the elements of PRC-019 affect the capabilities of the generating resource, the interval between this calibration can match that of the proposed MOD-025 capability declaration. Since that interval is proposed to be every 10 years, the PRC-019 interval too should be 10 years. These settings do not drift with time compared to historical analog based electronic systems.

The SDT should clarify “Facilities” for all NERC standards including PRC-019-3 and MOD-025-3. As written, Facilities could be individual BES generators rated at less than 1 MVA. The SDT should use the terms “BES plant” meaning: a) Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or b) Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Southern Company agrees and supports the comment provided by the SERC Generator Working Group who asks the question as to why this needs to be done every 5 or 6 years. Excitation systems don’t change and are usually black boxes that require the use of vendors and/or contractors to update.

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	

Comment	
Tacoma Power does not agree with the proposed Measure for Requirement R1. Mandating new graphical evidence of coordination every six years for synchronous units that had no equipment changes or settings changes in that time doesn't seem to serve any purpose. When a change is made, Requirement R2 requires new coordination to be performed. If the intent of R1 is to simply double check existing settings every six years, it should be sufficient to show that the settings and equipment haven't changed since the last PRC-019 study was performed. Tacoma Power recommends the following change to Measure M1 to specify that an additional study is not needed if an Entity demonstrates that no changes were made since the previous PRC-019 study (emphasis added to denote change) : M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-XDiagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, **documentation that settings did not change since the previous coordination study**, or other evidence that it performed a coordination study as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The SDT should clarify "Facilities" for all NERC standards including PRC-019-3 and MOD-025-3. As written, Facilities could be individual BES generators rated at less than 1 MVA. The SDT should use the terms "BES plant" meaning: · Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or · Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed language in PRC-019-3, Requirement R1 for the following reasons: Information developed under PRC-019-3 supports entity compliance activities under MOD-025-3. Given the linkage between PRC-019 and MOD-025 compliance obligations under Requirement R1 should be harmonized. For this reason, GOs and TOs should be required to conduct coordination of generating unit or plant capabilities, voltage regulating controls and protection at a maximum of every 10 years, consistent with MOD-025-3. The term "protection function" is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. We also understand that Project 2019-04 (Modifications to PRC-005-6) is considering how to define "protection functions" as it relates to inverter based resources. While both this SDT and the Project 2019-04 SDT have approval to add new glossary terms both should coordinate and align definitions. Add language to Attachment 1, Paragraph B that clearly states that control functions only need to be coordinated with protective functions of the same monitored parameter.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No

Document Name	
Comment	
Black Hills Coproration (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company agrees with EEI's comments regarding using a term that is not NERC defined. PGE believes that the Standard language should further clarify that a limiter must be coordinated with its associated protection function. PGE would like clarification on the intent/purpose of the Standard. Is it the coordination of voltage controls with other applicable limiters and protection functions or does it also cover all relevant electrical aspects of generation (equipment capability voltage controls, limiters, voltage, and current protection functions etc.) PGE requests guidance when voltage control mode is not actually used – what if a different mode is used?	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
The SDT should clarify "Facilities" for all NERC standards including PRC-019-3 and MOD-025-3. As written, Facilities could be individual BES generators rated at less than 1 MVA. The SDT should use the terms "BES plant" meaning: {C}· Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or {C}· Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The MRO NSRF believes the requirements in PRC-019 and MOD-025 should be harmonized to once every 10-years.	

R1.1.1 when coupled with Attachment 1, Paragraph A for synchronous machines makes it is quite clear that the intent is that a limiter must be coordinated with the associated protective functions of the same parameter. For example, a field over-excitation limiter would be coordinated with a field over-excitation trip but there would be no expectation to have a limiter of one parameter limit before the trip based on a different parameter. For example, it would not be necessary to show that the field over-excitation limiter would act to limit prior to the occurrence of a volts/hz trip. The wording of R1.2.1, R1.2.2, and Attachment 1, Paragraph B for IBR generating Facilities does not seem to include a stipulation that the control function need only be coordinated with the associated protective function for the given parameter. R1.2.1 only states that in-service power plant controller control functions occur before protective functions, R1.2.2 only states the in service control functions of the IBR units must be set to act before protective functions, and Attachment 1, Paragraph B is only a list of control, limiter, and protective function without any stipulation that control parameters only need be coordinated with the protective function of that same parameter. Example: R1.2.1 and R1.2.2 could be read to require that if a PQ limiter is applied in the PPC or on the IBR units, than the PQ limiter must be set to take action to limit before a trip were to occur for any parameter such as overvoltage of an individual IBR located at the extreme remote end of a collector under abnormal grid conditions and transients. Such an interpretation that any limiter must act before any protective function would result in limiters being set so tightly to avoid trips of remote IBRs in the collector system under extreme conditions but would greatly limit the reactive capability of the overall IBR generating facility to support the grid. Please add clarification to Attachment 1, Paragraph B that control functions only need to coordinated with protective functions of the same monitored parameter.

Information developed under PRC-019-3 supports entity compliance activities under MOD-025-3. Given the linkage between PRC-019 and MOD-025 compliance obligations under Requirement R1 should be harmonized. For this reason, GOs and TOs should be required to conduct coordination of

generating unit or plant capabilities, voltage regulating controls and protection at a maximum of every 10 years, consistent with MOD-025-3.

The term “protection function” is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. The MRO NSRF suggests that footnote 4 be revised to reference the protective functions outlined in Attachment 1. An example might be:

{C}· 4. A protective function includes an action performed by a Protection System device that replicate the functions listed in Attachment 1

Add language to Attachment 1, Paragraph B that clearly states that control functions only need to be coordinated with protective functions of the same monitored parameter.

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

What is the technical basis for requiring a coordination review be completed on all applicable Facilities on a six calendar year interval (other than alignment with the six calendar year interval in PRC-005)? Is this based on documented experience with "settings drift" in voltage regulating system controls, applicable equipment capabilities, and settings of the applicable protective functions? PRC-023-4, PRC-024-3, PRC-025-2, and PRC-026-1 do not have a periodic setting review element. PRC-027-1, Requirement R2 has a six-calendar years baseline requirement for verifying coordination or reviewing fault current and verifying coordination where the fault current change exceeds 15%. The drafting team should consider whether establishing a baseline coordination review for all applicable Facilities is sufficient, then require that coordination reviews be completed again only “prior to implementation of systems, equipment, or settings changes that will affect the coordination” as described in R2.

Likes 0	

Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
MP supports NSRF's comments.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The SDT should clarify "Facilities" for all NERC standards including PRC-019-3 and MOD-025-3. As written, Facilities could be individual BES generators rated at less than 1 MVA. The SDT should use the terms "BES plant" meaning: Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.	

NVE believes the requirements in PRC-019 and MOD-025 should be harmonized to once every 10-years.

R1.1.1 when coupled with Attachment 1, Paragraph A for synchronous machines makes it is quite clear that the intent is that a limiter must be coordinated with the associated protective functions of the same parameter. For example, a field over-excitation limiter would be coordinated with a field over-excitation trip but there would be no expectation to have a limiter of one parameter limit before the trip based on a different parameter. For example, it would not be necessary to show that the field over-excitation limiter would act to limit prior to the occurrence of a volts/hz trip. The wording of R1.2.1, R1.2.2, and Attachment 1, Paragraph B for IBR generating Facilities does not seem to include a stipulation that the control function need only be coordinated with the associated protective function for the given parameter. R1.2.1 only states that in-service power plant controller control functions occur before protective functions, R1.2.2 only states the in service control functions of the IBR units must be set to act before protective functions, and Attachment 1, Paragraph B is only a list of control, limiter, and protective function without any stipulation that control parameters only need be coordinated with the protective function of that same parameter. Example: R1.2.1 and R1.2.2 could be read to require that if a PQ limiter is applied in the PPC or on the IBR units, than the PQ limiter must be set to take action to limit before a trip were to occur for any parameter such as overvoltage of an individual IBR located at the extreme remote end of a collector under abnormal grid conditions and transients. Such an interpretation that any limiter must act before any protective function would result in limiters being set so tightly to avoid trips of remote IBRs in the collector system under extreme conditions but would greatly limit the reactive capability of the overall IBR generating facility to support the grid. Please add clarification to Attachment 1, Paragraph B that control functions only need to coordinated with protective functions of the same monitored parameter.

Information developed under PRC-019-3 supports entity compliance activities under MOD-025-3. Given the linkage between PRC-019 and MOD-025 compliance obligations under Requirement R1 should be harmonized. For this reason, GOs and TOs should be required to conduct coordination of generating unit or plant capabilities, voltage regulating controls and protection at a maximum of every 10 years, consistent with MOD-025-3.

The term “protection function” is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. NVE suggests that footnote 4 be revised to reference the protective functions outlined in Attachment 1. An example might be:

4. A protective function includes an action performed by a Protection System device that replicate the functions listed in Attachment 1

Add language to Attachment 1, Paragraph B that clearly states that control functions only need to be coordinated with protective functions of the same monitored parameter.

Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no comments. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	

Comment	
The NAGF generally agrees with the proposed language for PRC-019-3 R1. The NAGF recommends that the proposed language for M1 be revised as follows "Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as graphical representations of coordination (e.g. P-Q Diagram, R-X Diagram, Inverse Time Diagram), equivalent tables, the results of steady-state calculations or dynamic simulation studies, or other evidence."	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Who will be responsible for verifying coordination of Facility voltage regulating controls, limit functions, equipment capabilities, and protective functions for dynamic reactive resources and IBRs that are on the distribution system? Are there any cases where I5-included dynamic devices or I4-included IBRs are owned by an entity that is not registered as a transmission owner? If so, how will these devices by verified?	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation has no comments.

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	
Document Name	

Comment

No comment

Likes 0	
Dislikes 0	

Response

10. Do you agree the language proposed in PRC-019-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NVE asks the SDT to justify the reliability benefit of 90-calendar days. NERC has not shown any reliability risk justification for why 90-days would jeopardize the Bulk Electric System (BES). There is a long history of developing model data and performing analyses annually as adequate to maintain BES reliability. Therefore, the 90 days should be replaced with one calendar year unless the SDT can show a true reliability need for 90-days.

The term "protection function" is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. NVE suggests that footnote 4 be revised to reference the protective functions outlined in Attachment 1. An example might be:

4. A protective function includes an action performed by a Protection System device that replicate the functions listed in Attachment 1

The term in bullet 5 "IBR unit" should be changed to "Applicable Facilities"

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

No Comment.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

MP supports NSRF's Comments.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	No
Document Name	

Comment

How will entities verify that changes will NOT affect the coordination? While the intent of this language identified in the September 2022 PRC-019-3 Technical Rationale document is laudable, the current verbiage seems to require that the GO/TO "prove the negative". We suggest modifying the language in R2 as follows:

"If changes are identified that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to…"

While this proposed modification may seem minor on the surface, we believe that it allows greater flexibility for the entity when reviewing changes that may impact coordination while also meeting the stated intent of the SDT.

In other words, we believe that the current verbiage necessitates that the entity attempt to "prove the negative" by generating evidence "that a particular change made to systems, equipment, or settings will **not** affect the coordination".

Whereas we believe that the verbiage we proposed will only require evidence that the entity performed a coordination study whenever an impact to coordination is/was identified.

Lastly, we feel that the last bullet point in R2 needs further clarification that this only applies to IBR facilities. Power Plant Controller is a common term for the "Station Master" controller at an IBR facility; however, this could be mis-interpreted to include the Station Control System (a.k.a. DCS) at a synchronous generating facility. We propose the following modification:

"IBR facility power plant controller firmware or settings changes."

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No
Document Name	

Comment

Similar to R1, clarify that R2 is applicable for Generator Owners or Transmission Owners that own an applicable facility. We suggest the ***bolded*** statement be added: “Each Generator Owner and Transmission Owner ***with applicable facilities*** shall perform the coordination described in Requirement R1…”.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

We prefer language similar to PRC-019-2, R2 – “Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination….”.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

The MRO NSRF asks the SDT to justify the reliability benefit of 90-calendar days. NERC has not shown any reliability risk justification for why 90-days would jeopardize the Bulk Electric System (BES). There is a long history of developing model data and performing analyses annually as adequate to maintain BES reliability. Therefore, the 90 days should be replaced with one calendar year unless the SDT can show a true reliability need for 90-days.

The term “protection function” is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. The MRO NSRF suggests that footnote 4 be revised to reference the protective functions outlined in Attachment 1. An example might be:

{C}· 4. A protective function includes an action performed by a Protection System device that replicate the functions listed in Attachment 1

The term in bullet 5 “IBR unit” should be changed to “Applicable Facilities”

Likes 0	
Dislikes 0	

Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that the sequencing clarification of R2 (study first, then implement, then update documentation) is appropriate but conflicts with the instruction in footnote 3 to use only as-left settings. It is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor perform or update a PRC-019 study. PRC-019-3 should allow giving a go-ahead based on analysis of intended settings, then issuing a revised report within 90 days of implementation if there are any deviations between intended and as-left settings.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Coproration (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	

Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the core language of Requirement R2, but we have concerns with the following: Bullet 2 – EEI disagrees with replacing the defined term “Protection System” (previously used in PRC-019-2) with the undefined term protective functions. This could be resolved by either defining the term “protective functions” or replacing this term with the defined term Protection System. Bullet 5 – The term “IBR unit” should be changed to “Applicable Facilities” because it is possible that control system firmware changes or setting changes beyond IBRs could also impacts on coordination.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp asks NERC to justify the reliability benefit of 90-calendar days as “arbitrary and capricious”, meaning NERC entirely failed to show any reliability risk justification as to why 90-days would jeopardize the Bulk Electric System (BES). There is a long history of developing model data and performing analyses annually as adequate to maintain BES reliability. Therefore, the 90 days should be replaced with one calendar year unless the SDT can show a true reliability need for 90-days.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	

Buckeye Power, Inc. supports the comments of ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation (BHP) agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

Tacoma Power does not agree that the language proposed in Requirement R2 is clear. Tacoma Power recommends adding this sentence from the technical rationale into the Requirement language: “If an entity determines or is advised that a particular change made to systems, equipment, or settings will not affect the coordination described in Requirement R1, then coordination need not be performed.”

This additional sentence clarifies that coordination does not need to be performed if the Requirement R1 coordination isn’t impacted by a system/equipment/settings change (as is stated in the technical rationale). Stating that an action is required under a specific condition does not automatically mean that the action is not required if the condition isn’t met. For example, saying “When it is noon, I must eat” does not automatically mean “If it is not noon, I will not eat”. The lack of an additional clarifying sentence exposes an already complicated standard to significant risk of misinterpretation by regulators and SMEs.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Recommends the 90 days be extended to 180 days. While settings undergo a preliminary coordination prior to commissioning, it is not unusual for these settings to be adjusted during the commissioning, which results in a commissioned unit that is in compliance with PRC-019. These settings must undergo the same rigorous Engineering Analysis and Peer Review as the preliminary settings. 90 days does not allow enough time to complete the analysis, peer review and documentation. Recommend changing R2 to read “and update associated coordination documentation within 180 calendar days after the return to in-service date.” This will eliminate the potential for a unit to be out of service while waiting on compliance documentation.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Section B, R2: A full coordination study should not be required for IBR or PPC firmware changes unless there is a specific addition of new limiter settings.

Southern Company agrees with the MRO NSRF who asks the SDT to justify the reliability benefit of 90-calendar days. NERC has not shown any reliability risk justification for why 90-days would jeopardize the Bulk Electric System (BES). There is a historical practice of of developing model data and performing analyses annually as adequate to maintain BES reliability. Therefore, the 90 days should be replaced with one calendar year unless the SDT can show a true reliability need for 90-days.

The term “protection function” is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. The MRO NSRF suggests that footnote 4 be revised to reference only the protective functions outlined in Attachment 1. We reiterate that certain items in the appearing in the IBR list of functions are incorreclty labelled as protective functions and are purely control strategies employed when the power conversion process is otherwise uncontrollable (e.g. phase lock loop lost). An example might be:

4. A protective function includes an action performed by a Protection System device that replicate the protection functions listed in Attachment 1

Southern Company agrees with the NAGF observation that the sequencing clarification of R2 (study first, then implement, then update documentation) is appropriate but conflicts with the instruction in footnote 3 to use only as-left settings. It is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor perform or update a PRC-019 study. PRC-019-3 should allow giving a go-ahead based on analysis of intended settings, the issuing a revised report within 90 days of implementation if there are any deviations between intended and as-left settings.

Likes 0	
Dislikes 0	

Response

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The associated coordination documentation should be updated prior to returning the equipment to in-service status. It seems impossible to make coordinated changes prior to implementation of systems without appropriate documentation and coordination studies.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #10.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Instead of 90 days, 180 days should be allowed to update associated coordination documentation after the return to in-service date.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). It is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor re-perform or update the PRC-019 study. PRC-019 should provide latitude for the coordination study based on analysis of intended settings, then allow for issuance of a revised report within 90 days of implementation if there are any deviations between intended and as-left settings identified.

Alison Mackellar on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). It is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor re-perform or update the PRC-019 study. PRC-019 should provide latitude for the coordination study based on analysis of intended settings, then allow for issuance of a revised report within 90 days of implementation if there are any deviations between intended and as-left settings identified.

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS recommends that Requirement 2 (bullet 5) only apply to IBR unit control system firmware or settings changes that effect the protection of the unit.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF asks the SDT to justify the reliability benefit of 90-calendar days. NERC has not shown any reliability risk justification for why 90-days would jeopardize the Bulk Electric System (BES). There is a long history of developing model data and performing analyses annually as adequate to maintain BES reliability. Therefore, the 90 days should be replaced with one calendar year unless the SDT can show a true reliability need for 90-days.

The term “protection function” is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. The MRO NSRF suggests that footnote 4 be revised to reference the protective functions outlined in Attachment 1. An example might be:

- 4. A protective function includes an action performed by a Protection System device that **replicate the functions listed in Attachment 1**

The term in bullet 5 “IBR unit” should be changed to “Applicable Facilities”

Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC agrees with the EEI comments	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
As-left settings will not be available prior to implementation.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the core language of Requirement R2, but has the same concerns as provided in the EEI input for Q10. PG&E agrees with the EEI input for Q10 regarding Bullets 2 and 5.	
Likes 0	

Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
The SERC Generator Working Group suggests changing the requirement to 180 days, instead of 90 days, following commissioning as study results take time as they are usually coming from multiple vendors. We also request better definitions of in-service and commissioning as there are usually issues with the coordination due to multiple party involvement.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
For Measure M2, during the NERC SDT Webinar discussing PRC-019-3, there was a clarification that evidence for R2 would be focused on the coordination study that would need to be performed within 90 calendar days of implementation of any changes. BC Hydro suggests that the Measure M1 clarify or provide examples of what would be considered suitable evidence of coordination **prior** to implementation of systems (e.g. settings design sheets/calculations would be acceptable or does it have to be a coordination study that would require a mandatory update within 90 calendar days?)	

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The sequencing clarification of R2 (study first, then implement, then update documentation) is appropriate but conflicts with the instruction in footnote 3 to use only as-left settings. That is, it is impractical to install or reprogram a relay or AVR, identify the as-left settings, then wait a month or two before restarting the unit to have a contractor perform or update a PRC-019 study.

PRC-019-3 should allow giving a go-ahead based on analysis of intended settings, then issuing a revised report within 90 days of implementation if there are any deviations between intended and as-left settings.response.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	No
Document Name	

Comment

Although the footnote does not appear here, it references the coordination described in R1

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

How will entities verify that changes will NOT affect the coordination? While the intent of this language identified in the September 2022 PRC-019-3 Technical Rationale document is laudable, the current verbiage seems to require that the GO/TO "prove the negative". We suggest modifying the language in R2 as follows:

"If changes are identified that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to…"

While this proposed modification may seem minor on the surface, we believe that it allows greater flexibility for the entity when reviewing changes that may impact coordination while also meeting the stated intent of the SDT.

In other words, we believe that the current verbiage necessitates that the entity attempt to "prove the negative" by generating evidence "that a particular change made to systems, equipment, or settings will **not** affect the coordination".

Whereas we believe that the verbiage we proposed will only require evidence that the entity performed a coordination study whenever an impact to coordination is/was identified.

Lastly, we feel that the last bullet point in R2 needs further clarification that this only applies to IBR facilities. Power Plant Controller is a common term for the "Station Master" controller at an IBR facility; however, this could be mis-interpreted to include the Station Control System (a.k.a. DCS) at a synchronous generating facility. We propose the following modification:

"IBR facility power plant controller firmware or settings changes."

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

1) Manitoba Hydro does not agree that a coordination study is required for IBR or power plant controller firmware or setting changes if these changes do not affect the coordination. The proposed wordings will create unnecessary work and further language is required to clarify the intent behind this.

2) A process and methodology need to be included in the standard such as what defines the unit in service? Is this the COD (commercial operation date) of the machine, supplying energy, turned over to system control? This is all arbitrary and more work on the standard is required.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

Similar to the reasoning and concerns expressed in Response #9, the inclusion of "IBR unit control system firmware or settings changes" and "Power plant controller firmware or settings changes" may prove problematic. 90 days is an extremely aggressive timeframe for the Generator Owner or Transmission Owner to obtain information and insight that might possibly be known only by the manufacturer, and potentially including proprietary information. Rather than 90 days, AEP recommends that a) 180 days be allowed to document a plan to obtain this additional information from the manufacturer and b) an additional 90 days to perform the coordination per R1.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

11. Do you agree the language proposed in PRC-019-3 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Examples diagrams have been removed from PRC-019, and are no longer found in either the standard or its associate Technical Rationale document. We believe this information is helpful and recommend that it be retained within the Technical Rationale document, and that it also be updated to reflect the proposed revisions to the standard (including for IBRs).	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
1) Voltage dependent protection functions needs to be clarified what is the safe voltage limit. Currently voltage based functions are coordinated at 1 p.u. and this coorindation will hold little value when an event such a loss of field occurs and the voltage will drop. 2) Some generators/synchronous condensers do not have equipment capability information provided such as volts per hertz capability due to the age of the equipment. Further wording in the standard needs to be clarified what to do if this information is not provided or not available.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

"Synchronous generator/condenser reactive capabilities," should be removed from Att. 1 part A. This addition to the criteria of PRC-019-2 has no relevance to showing that limiters act before trips and trips occur prior to damage. The knowledge that capabilities in turn may fall short of limiters may be of slight interest but creates no reliability benefit.

Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	

Xcel Energy supports the comments of the EEI and the MRO NSRF.

*Note: Xcel Energy does not agree with EEI's comment in response to #2 in Part B Concerns.

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E does not agree with the proposed language provided in Attachment 1. PG&E agrees with the input provided by EEI for Q11 on the concerns for Part A and B.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
The list of IBR functions is extensive. Refer to Question 9 response regarding more guidance is needed on how coordination between all of these elements is shown. Additionally, legacy plants may no longer have inverter OEMs in business for consultation. Therefore, collecting details that were not standard to give to the customer when the plant was commissioned, such as momentary cessation, is impossible. The SDT should consider legacy units where information may not be available.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	

Comment	
BHC agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Bullets 1, 2 & 3 (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function) appear to duplicate obligations identified in MOD-025, Attachment 1, Section 2, Part 5. If this is incorrect, please clarify how a violation under PRC-019, Attachment 1, Part A would not also result in a violation of MOD-025-3, Section 2, Part 5. **Part B Concerns**: The first paragraph of Part B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter. (See our response to Question 9 above.) The references to collector feeders appears to include non-BES Facilities. References to non-BES Facilities should be removed from the list or clarifying language that makes it clear that non-BES facilities are not to be included under PRC-019-3.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS recommends removing the eleventh bullet “IBR unit phase lock loop protective function” from Attachment 1, Section B as it is not necessary for reliability and it may be difficult or impossible to obtain information on the behavior of the phase lock loop from the manufacturer for both new and existing units.

AZPS also supports the following comments submitted by EEI on behalf of their members:

a) Attachment 1, Section A, Bullets 1, 2 & 3 (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function) appear to duplicate obligations identified in MOD-025, Attachment 1, Section 2, Part 5. If this is incorrect, please clarify how a violation under PRC-019, Attachment 1, Part A would not also result in a violation of MOD-025-3, Section 2, Part 5.

b) In Attachment 1, the first paragraph of Section B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter. (See our response to Question 9 above.)

c) The references to collector feeders appears to include non-BES Facilities. References to non-BES Facilities should be removed from the list or clarifying language that makes it clear that non-BES facilities are not to be included under PRC-019-3.

Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	

Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.

Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No

Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The example diagrams that were removed should be returned along with new examples added specifically for IBRs.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #11.	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	No
Document Name	
Comment	

Part B Concerns:

The first paragraph of Part B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter. (See our response to Question 9 above.)

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Attachment 1, Section A: Recommend removal of "Distributed control system (DCS) voltage/VAR limit settings." These DCS limits are often set completely independent of protection engineers' input and are at the discretion of controls engineers and/or plant operations personnel.

Attachment 1, Section B: See first note above. Items such as "Reactive compensating devices voltage control functions," "IBR unit phase lock loop protective function," "IBR unit momentary cessation protection function" should be removed from this list. Phase lock loop and momentary cessation are not protection functions and have been liberally renamed; these are loss-of-control functions.

Please review Southern Company comments in response to Question 9 above related to control functions listed in Section B of Attachment 1.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

Black Hills Corporation (BHP) agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response
Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
No. See responses in questions 9 and 10.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not agree with all parts of Attachment 1. Please note the following concerns:

Attachment 1

Part A Concerns:

Bullets 1, 2 & 3 (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function) appear to duplicate obligations identified in MOD-025, Attachment 1, Section 2, Part 5. If this is incorrect, please clarify how a violation under PRC-019, Attachment 1, Part A would not also result in a violation of MOD-025-3, Section 2, Part 5.

Part B Concerns:

- The first paragraph of Part B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter. (See our response to Question 9 above.)
- The references to collector feeders appears to include non-BES Facilities. References to non-BES Facilities should be removed from the list or clarifying language that makes it clear that non-BES facilities are not to be included under PRC-019-3.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	

Comment

Black Hills Coproration (BHP) agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.

Answer	No
Document Name	

Comment

Portland General Electric Company supports the comments provided by EEI.

\PGE also observes that if the intent is to cover stator current capabilities and protective functions, Time vs. Field Current and Time vs Stator current are neither a capability nor a protective function. PGE suggests Rotor Capability, Stator Capability, and any associated protective functions.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	

Bullets 1, 2 & 3 (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function) appear to duplicate obligations identified in MOD-025, Attachment 1, Section 2, Part 5. If

this is incorrect, please clarify how a violation under PRC-019, Attachment 1, Part A would not also result in a violation of MOD-025-3, Section 2, Part 5.

Part B Concerns:

The first paragraph of Part B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter. (See our response to Question 9 above.)

The references to collector feeders appears to include non-BES Facilities. References to non-BES Facilities should be removed from the list or clarifying language that makes it clear that non-BES facilities are not to be included under PRC-019-3.

Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

MP supports NSRF's comments.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	

No Comment.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Bullets 1, 2 & 3 (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function) appear to duplicate obligations identified in MOD-025, Attachment 1, Section 2, Part 5. If this is incorrect, please clarify how a violation under PRC-019, Attachment 1, Part A would not also result in a violation of MOD-025-3, Section 2, Part 5. **Part B Concerns**: The first paragraph of Part B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter. (See our response to Question 9 above.) The references to collector feeders appears to include non-BES Facilities. References to non-BES Facilities should be removed from the list or clarifying language that makes it clear that non-BES facilities are not to be included under PRC-019-3.	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no comments. Kimberly Turco on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no comments. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	

Response	

12. The SDT believes the language of PRC-019-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Michael Whitney - Northern California Power Agency - 3

Answer	No
Document Name	

Comment

The SDT has not provided a cost estimate nor a cost/benefit analysis. No further standards should be developed if this vital budgeting and benefit information is not provided to impacted registered entities and vetted by industry.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

The SDT has not provided a cost estimate nor a cost/benefit analysis. No further standards should be developed if this vital budgeting and benefit information is not provided to impacted registered entities and vetted by industry.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

The SDT has not provided a cost estimate nor a cost/benefit analysis. No further standards should be developed if this vital budgeting and benefit information is not provided to impacted registered entities and vetted by industry.

Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
With the proposed language in Requirement R2, we do not support a periodic review basis for Requirement R1. It is unclear how a periodic review will improve reliability.	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question nine and ten.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
No. See responses in questions 9 and 10.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	No
Document Name	
Comment	
Agreement with the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Performing the coordination study specified by the current draft of PRC-019 for all of the invidual generatoring resources in the proposed scope is an extremely time consuming and labor intensive and will easily bring contractors millions of dollars in revenue annually at the expense of the responsible entitles and their rate payers.

Several of the capability limiting functions identified in this draft of PRC-019 overlap with the same capability limiting functions which are to be studied in MOD-025. Careful consideration is needed to eliminate the duplication which currently exists between the two draft standards.

In Attachment 1, Section B, the paragraph above the bulleted list should be modified to clearly state that control functions (limiters) only need to be coordinated with protective functions of the same monitored parameter.

Collector feeders non-BES Facilities. References to non-BES Facilities should be removed from the list so that it is clear that non-BES facilities are not included in the scope of PRC-019-3.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
A repetitive time-based coordination requirement, independent of a change management system, is not favorable to pass a cost/benefit analysis.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
See our responses to Questions 9, 10, and 11 for suggested improvements. Submitted on behalf of Exelon, Segments 1, 3	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	

These activities are expensive to conduct and will only increase in cost due to the expansion of the requirements.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
As stated above, Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). External vendors are routinely hired to perform the coordination studies and therefore this proposed change significantly increases the cost to the Generator Owner. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment	
As stated above, Constellation does not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning). External vendors are routinely hired to perform the coordination studies and therefore this proposed change significantly increases the cost to the Generator Owner. Kimberly Turco on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question nine and ten.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	

Answer	No
Document Name	
Comment	
As the desired coordination is unclear, it is difficult to determine what the cost will be.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
At this time PG&E cannot determine if the modifications are cost effective.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	

Comment	
The changes recommended above will improve the cost-effectiveness of PRC-019-3.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
These changes will increase the workload, processes and evidence collected.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
MP will not comment on Cost Effectiveness.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	

See comment #6

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Coproration (BHP) will not respond to the cost effectiveness.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black HIlls Corporation (BHP) will not respond to cost effectiveness.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE does not have comments.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	
Document Name	

Comment

BHC will not respond to cost effectiveness.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

No comment

Likes 0	
Dislikes 0	

Response

13. The SDT proposes a 1-year implementation plan for PRC-019-3 Requirement R2. For Requirement R1 with reoccurring periodicity for existing Facilities, the Implementation Plan proposes a six year reoccurring periodicity from the date of previous coordination date of PRC-019-2 R1. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period.

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
As the expectations are unclear and coordination guidance is not available, it is unclear to AES Clean Energy what the best implementation should be.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question nine and ten. The MRO NSRF believes the requirements in PRC-019-3 and MOD-025-3 should be harmonized to once every ten-years.	
Likes 0	
Dislikes 0	

Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS recommends that PRC-019 should be harmonized with MOD-025-3 as described in our comments to Question 9 above.	
Likes 0	
Dislikes 0	
Response	
Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The periodicity should be once every 10 years.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
The Implementation Plan should be divided into two. One for existing generators and one for IBR. The existing should be as part of the next frequency of coordination. The cycle should be removed. One time performance is adequate for standards such as PRC-024 and PRC-025. If there needs to be a cycle, then 10 years to coincide with MOD-025 testing makes more sense.	
Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Because the coordination of the elements of PRC-019 affect the capabilities of the generating resource, the interval between this calibration can match that of the proposed MOD-025 capability declaration. Since that interval is proposed to be every 10 years, the PRC-019 interval too should be 10 years. These settings do not drift with time compared to historical analog based electronic systems.	
Likes 0	

Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Agreement with the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

Please see the MRO NSRF's comments in question nine and ten. The MRO NSRF believes the requirements in PRC-019-3 and MOD-025-3 should be harmonized to once every ten-years.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

The standard uses the term "calendar years". The Implentation Plan should use the same language and require a periodicity based on calendar years.

The implementation plan does not discuss existing resources that come into scope due to update applicable facilities language. For any resource that comes into scope due to changes in the applicable facilities, implementation plan should allow 2-5 years, as was allowed in the PRC-019-2 implementation plan.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
The 6 year timeline is acceptable.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the 1 year Implementation Plan for PRC-019-3.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation agrees with the 6 year periodicity from the last protection study performed in order to align with historical work completed under PRC-019-2

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation agrees with the six (6) year periodicity from the last protection study performed in order to align with historical work completed under PRC-019-2.

Alison Mackellar on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	

No comments

Likes 0	

Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	Yes
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #13.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
While EEI supports the proposed implementation plan for PRC-019-3, PRC-019-3 should be harmonized with MOD-025-3. (See our comments to Question 9 above)	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed plans.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Pedro Juarez, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Michael Whitney - Northern California Power Agency - 3

Answer	
Document Name	

Comment
No comment

Likes 0	
Dislikes 0	

Response

14. Provide any additional comments on PRC-019-3 and technical rationale document for the standard drafting team to consider, if desired.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
Under the Applicability Section (Facilities) within 4.2.4.2 collector feeder(s) are listed which appears to include non-BES facilities under PRC-019-3. If this is the intent, please remove the reference to collector feeder(s) under 4.2.4 or provide an explanation of what BES Facilities are to be applicable under the title of "collector feeder(s)."	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

4.2.1 and 4.2.2 could be combined into one item that references BES inclusion I2. BES Inclusion I2 includes the GSU as part of the generating resource. Considering adding a footnote clarifying whether the GSU is included in 4.2.1 and 4.2.2. Be sure not to conflict with existing footnote 2 which discusses GSUs, but only for IBR.

4.2.3 Specifies dynamic reactive resources, and 4.2.3.1 further includes Synchronous Condensors. It's not clear whether other types of dynamic reactive resources are included.

4.2.4 is unclear about what is being included. The individual items (4.2.4.1, 4.2.4.2, 4.2.4.3, 4.2.4.4, 4.2.4.5) are redundant if I4 definition already defines what is included.

4.2.5 should include a reference to I3 of the BES definition.

Consider updating the order of the applicable facilities to match their respective order in the BES definition inclusions: I2, I3, I4, I5.

The SDT should clarify "Facilities" for all NERC standards including PRC-019-3 and MOD-025-3. As written, Facilities could be individual BES generators rated at less than 1 MVA. The SDT should use the terms "BES plant" meaning:

{C}· Generators with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater or

{C}· Aggregate generators aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

4.2.3.1 Synchronous condenser

Why are synchronous condensers called out separately in section 4.2.3.1? Does section 4.2.3 not include other dynamic reactive resources?

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	

Document Name	
Comment	

The footnote clarifying what constitutes an IBR unit is not referenced until Requirement 1.2 on page 4 of the proposed version of PRC-019. We recommend adding this clarification to Section 4.2.4.1 to aid the GO in identifying applicable facilities.

Additionally, it is our opinion that section 4.2.5 should be modified to reference Inclusion I3 of the BES definition in order to be consistent with sections 4.2.1 through 4.2.4. Furthermore, this modification would be in accordance with the facilities section of the September 2022 PRC-013-3 Technical Rationale which states: "The proposed standard links applicability to the BES definition (as opposed to defined rating or other thresholds) to be sure that now and in the future, should the BES definition be modified, the standard is consistent with applicable BES facilities."

Please consider the following proposed verbiage as an example:

"Individual Blackstart Resource identified through Inclusion I3 of the BES definition."

We appreciate the effort that was put into improving this standard and a grateful for the opportunity to provide comments.

Additional Comments:

For questions 9 and 12 we had comments with a different perspective that we also want to provide to the SDT for consideration.

Question 9 - Coordination based on elapsed time is arbitrary, administrative, and unnecessary. Event driven coordination (equipment/setting change or identification of inaccuracy) would be more efficient (as covered by R2 in the previous version)

Question 12 - Addition of IBR’s is clearly necessary in today’s environment. However, arbitrary periodic re-coordination rather than the more logical event driven coordination adds to the administrative burden without a benefit to the BES. As more and more administrative type work is added, it becomes more likely that real issues that do impact the BES are overlooked.

Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1

Answer	
Document Name	
Comment	

Applicability in Section 4 is for dynamic reactive resources (identified through Inclusion I5) in Section 4.2.3 and for inverter-based resources in Section 4.2.4 listed as examples starting with stating that the listed examples are “included.” Noting that Inclusion I5 of the BES definition excludes generators [without specifying that Inclusion I5 likely only is related to synchronous condensers under the category of electrical machines included under dynamic devices] the explicit listing/inclusion of synchronous condensers makes sense, but it might still be worth adding examples of FACTS (Flexible AC Transmission System) components such as SVC and STACOM (cf. MOD-025) which also could serve as dynamic reactive resources to this list. Further, the 20 MVA threshold is inconsistent with Inclusion I5 of the BES Definition which is based on elements connected at 100 kV or higher.

The listing of included elements in Section 4.2.4 for inverter-based resources includes multiple elements such as collector buses and collector feeders [unless aggregating to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above] as well as generator step-up (GSU) transformers and (general reference to any?) static or dynamic reactive compensating devices which are not depicted as BES elements in the figures of

Section II.4 BES Inclusion I4 Bulk Electric System Definition Reference Document (version 2, April 2014). Suggest aligning the Applicability of Facilities as listed in Section 4.2 of PRC-019 with the BES Definition (Inclusion I4), including the BES Definition Reference Document.

Please consider changing Applicability section 4.2.5 "Any Blackstart Resource" to read as "A Blackstart Resource."

Please consider updating Compliance Section C to include the abbreviation (CEA) for Compliance Enforcement Authority; and use the CEA abbreviation in Compliance section 1.2.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	
Document Name	

Comment

Under the Applicability Section (Facilities) within 4.2.4.2 collector feeder(s) are listed which appears to include non-BES facilities under PRC-019-3. If this is the intent, please remove the reference to collector feeder(s) under 4.2.4 or provide an explanation of what BES Facilities are to be applicable under the title of “collector feeder(s).”

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	

Document Name	
Comment	
NPCC Regional Standards Committee (RSC) supports the drafting team proposal on the project.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	
Portland General Electric Company supports the comments provided by EEI. PGE recommends including examples of coordination graphs in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	

Comment	
Black Hills Coproration (BHP) supports the EEI comments of similar concerns with the Applicability Section (Facilities) in PRC-019-3 similar to concerns expressed in Question 8 above.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
While the term coordination is understood as it relates to System Protection coordination studies, coordination studies under PRC-019 include the coordination of protection functions with controls, equipment capabilities and resource control limits. To ensure that entities conduct PRC-019 studies consistently, coordination as intended under PRC-019-3 should be defined. Under the Applicability Section (Facilities) within 4.2.4.2 collector feeder(s) are listed, which appears to include non-BES facilities under PRC-019-3. If this is the intent, please remove the reference to collector feeder(s) under 4.2.4 or provide an explanation of what BES Facilities are to be applicable under the title of “collector feeder(s).”	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
RF recommends the SDT clarify whether transmission-connected dynamic reactive devices including SVCs, STATCOMs, LCC HVDC, and/or VSC HVDC are addressed by PRC-019 Applicability Section 4.2.3 (Reference SAR Detailed Description 1.d). If the SDT intends “including” in Applicability sections 4.2.3 and/or 4.2.4 to mean “exclusively including,” RF recommends revising for clarity (either by rewording or by explicitly listing exclusions). RF recommends the SDT collaborate with the NERC System Protection and Control Working Group to update the PRC-019 Technical Reference document and/or Implementation Guidance prior to the proposed standard revision being approved (or at least prior to the new standard revision becoming effective). With the removal of the Examples of Coordination that were included in PRC-019-2, external reference documents will help to provide industry with guidance in applying the new standard.	

Likes 0	
Dislikes 0	

Response

Ryan Strom - Buckeye Power, Inc. - 5 - RF

Answer	
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES Power Marketing.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

Agreement with the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	
Document Name	
Comment	
Applicability Section: The addition “4.2.4.2 Collector bus(es) and collector feeder(s);” to the applicability section is incongruent with Inclusion I4 of the BES definition and should be removed. The circuitry between those individual resources and the point of aggregation to a power level of 75MVA is not included by Inclusion I4 and are non-BES facilities.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	
Document Name	
Comment	
PRC-019 – It seems odd not to include individual generating units that do not have voltage control and SSL through Inclusion I4. As stated in the long description section 1B, these same generating facilities are suggested to be subject to the standard since they perform “system VAR support and reliability”. When enough inverter sites drop off, the system voltage will change and affect the reliability. Within the Rationale section page 2, there’s a paragraph discussing the applicability of non-generation transmission connected reactive resources such as static VAR compensators (FACTS). So, is PRC-19-3 applicable to these reactive resources or, is there merely a non-required recommendation? We	

have 115kV FACTS and numerous < 20MVA transmission reactors and would like to know if these non-generation transmission connected reactive resources will be applicable facilities under PRC-019-3.

In addition, where does it say that firmware or software “upgrades” are debatable as “controller upgrades and/or changes” in part 2C. With the implementation of constant controls software patches (distributed, independent, or remote), network interface patches, firewall operating systems, desktop software, hardware IO interface firmware, IO branch controller firmware, PLC or node controllers, network firmware updates, field instrumentation, system analyzers…… There would be no end to reporting the “settings updates”. Seems that this is missing the definition of “controller upgrades and/or changes” in part 2C. If one is going to take the changes to that level, every time a control change is written into the EEPROM, a reconciliation is performed to a controller for autotuning changes and then written to the controller, or even a manual tune operation written into the controller there is a control change. It was understood the “controller upgrades and/or changes” to be those that directly affect the AVR and PSS.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	
Document Name	

Comment

NRG feels that there needs to be better coordination with the definition of protection systems and/or functions throughout the standards so that all PRC and MOD standards follow the same definition to remove confusion over applicability.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #14.

Evergy mistakenly voted Yes on several ballot questions in Segment 6. All of Evergy's ballot votes should have been Negative votes matching our other ballots. We are letting you know because it does not appear that you can change a vote after it has been cast.

Likes 0	
Dislikes 0	

Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Sheraz Majid - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	
Request clarity with 4.2.3, specifically for the use of the word "including" as this could imply synchronous condensor and other dynamic reactive resouces. Also request explicit mention of exclusions e.g. SVCs be mentioned in section 4.	
Likes 0	
Dislikes 0	
Response	
Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	
Document Name	
Comment	
Exelon agrees with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
Consider requiring the addition of Pmax and Pmin points (composite capability curve) to the P and Q diagram. This will allow the retirement of MOD-025.	
Likes 0	
Dislikes 0	
Response	

Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	
Document Name	
Comment	
Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
No additional comments. Alison Mackellar on behalf of Contellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

No additional comments.

Kimberly Turco on behalf of Contellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members:

While the term coordination is understood as it relates to System Protection coordination studies, coordination studies under PRC-019 include the coordination of protection functions with controls, equipment capabilities and resource control limits. To ensure that entities conduct PRC-019 studies consistently, coordination as intended under PRC-019-3 should be defined.

Under the Applicability Section (Facilities) within 4.2.4.2 collector feeder(s) are listed which appears to include non-BES facilities under PRC-019-3. If this is the intent, please remove the reference to collector feeder(s) under 4.2.4 or provide an explanation of what BES Facilities are to be applicable under the title of “collector feeder(s).”

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
Under the Applicability Section (Facilities) within 4.2.4.2 collector feeder(s) are listed which appears to include non-BES facilities under PRC-019-3. If this is the intent, please remove the reference to collector feeder(s) under 4.2.4 or provide an explanation of what BES Facilities are to be applicable under the title of “collector feeder(s).”	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC supports the EEI comments of similar concerns with the Applicability Section (Facilities) in PRC-019-3 similar to concerns expressed in Question 8 above.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 1	
Answer	
Document Name	
Comment	
NextEra Energy (NEE) appreciates the opportunity to provide input regarding the proposed changes to MOD-025. Because of the growing number of assets, companies need more time to implement the proposed changes to MOD-025 and NEE proposes a 36-month implementation plan instead of the proposed 1 year plan for requiements 3 and 4	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E supports the input provided by EEI for Q14 – provide a definition of coordination under PRC-019-3 and facilities captured under “collector feeders".	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	

The SERC Generator Working Group notes that the standard accounts for commissioning but asks about the discovery of changes and how that should be handled.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
In the VSL tables for R1, the timeframes do not reference calendar years/months. BC Hydro suggest revising for consistency with the Requirement R1, which defines periodicity based on calendar years.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	

Xcel Energy supports the comments of the EEI and the MRO NSRF. *Note: Xcel Energy does not agree with EEI's comment regarding "collecter feeder(s)" in response to this question.

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	
Document Name	PRC-019 and MOD-025 draft 1 comments.docx

Comment
Comments for PRC-019-3/MOD-025-3 Draft 1 on attached document.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	

Comment

No additional comments.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

AEPC signed on to ACES comments:

The footnote clarifying what constitutes an IBR unit is not referenced until Requirement 1.2 on page 4 of the proposed version of PRC-019. We recommend adding this clarification to Section 4.2.4.1 to aid the GO in identifying applicable facilities.

Additionally, it is our opinion that section 4.2.5 should be modified to reference Inclusion I3 of the BES definition in order to be consistent with sections 4.2.1 through 4.2.4. Furthermore, this modification would be in accordance with the facilities section of the September 2022 PRC-013-3 Technical Rationale which states: "The proposed standard links applicability to the BES definition (as opposed to defined rating or other thresholds) to be sure that now and in the future, should the BES definition be modified, the standard is consistent with applicable BES facilities."

Please consider the following proposed verbiage as an example:

"Individual Blackstart Resource identified through Inclusion I3 of the BES definition."

Lastly, we appreciate the effort that was put into improving this standard and a grateful for the opportunity to provide comments.

Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

1) An additional requirement should be added to ensure coordination between the generator owner and the transmission owner. We need to follow suit such as Requirement 4 in PRC-024 that if the transmission owner requests information for protection and control coordination, the generator owner must provide this information to the planning coordinatator or the transmission owner.

2) A new sub requirement to R1 should be added that requires all Generator and Transmission Owners of new equipment to have limiters for new capacity on the system enabled. This will ensure that untilites are not disabling limiters to ensure compliance.

3) Under 4.2 Facilities, it is not very clearly stated in 4.2.3 if BES connected SVCs that are not part of an IBR would be applicable to this standard or not. The wording needs to be changed to make it clear what dynamic reactive resources are required to be included.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response