Comment Report

Project Name:	2020-06 Verifications of Models and Data for Generators | Draft 3
Comment Period Start Date:	6/7/2023
Comment Period End Date:	7/21/2023
Associated Ballots:	2020-06 Verifications of Models and Data for Generators Implementation Plan AB 3 OT 2020-06 Verifications of Models and Data for Generators MOD-026-2 AB 3 ST

There were 77 sets of responses, including comments from approximately 200 different people from approximately 130 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the language proposed in MOD-026-2 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree with the language proposed in MOD-026-2 Requirements R2 and R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Do you agree with the language proposed in MOD-026-2 Requirements R4 and R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you agree with the language proposed in MOD-026-2 Requirement R6? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you agree with the language proposed in MOD-026-2 Requirements R7, R8, and R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. Do you agree with the language proposed in MOD-026-2 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

7. The standard drafting team (SDT) believes the language of MOD-026-2 addresses the issues outlined in the 2 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.

8. The SDT proposes a 2-year implementation plan for MOD-026-2 Requirements R1, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 and R7 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained for Requirements R2-R5 from the date of previous model verification. Do you agree with the proposed implementation plan timeframes? If you think an alternate timeframe is needed, please propose an alternate implementation plan with detailed explanation.

9. Provide any additional comments for the SDT 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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC 2023	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
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
Public Utility District No. 1 of Chelan County	Glen Pruitt	1		CHPD Voters	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC

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
					John Nierenberg	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
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Chris Adams	East Kentucky Power Cooperative	3	SERC
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE

					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc	1	MRO
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO

					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	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
Southwest Power Pool, Inc. (RTO)	Matthew Harward	2	MRO,SERC,WECC	SPP Standards Review Group	Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					Shannon Mickens	Southwest Power Pool, Inc.	2	MRO
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
					Frank Lee	Pacific Gas and Electric Company	5	WECC

National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC
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
Patricia Robertson	Patricia Robertson		WECC	BC Hydro Balloters	Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
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
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC

					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	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
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Joshua London	Eversource Energy	1	NPCC
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and 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
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric	1	SERC

						Cooperative, Inc.		
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree with the language proposed in MOD-026-2 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	No
Document Name	
Comment	

Requirement R1 **continues** to use inconsistent possessive form of Transmission Planner and the representative pronoun.

The main body of Requirement R1 should be revised to:

Each Transmission Planner and its Planning Authority shall jointly develop dynamic model requirements and processes. The dynamic model requirements and processes shall be made available to the Generator Owner and Transmission Owner by the its Transmission Planner, and include at a minimum the following:

The Requirement R1, Part 1.3 should be revised to:

Acceptance criteria used by the its Transmission Planner to determine disposition in Requirement R8 including at a minimum the following:

The Requirement R1, Part 1.4 should be revised to:

Process for Generator Owner or Transmission Owner to provide verified models to the its Transmission Planner;

The Requirement R1, Part 1.6 should be revised to:

Process for Generator Owner or Transmission Owner to obtain model data from the its Transmission Planner's database for an existing Facility owned by the Generator Owner or Transmission Owner within 90 calendar days of receiving a written request.

2. Requirement R1, Part 1.6 **continues** perpetuates an inappropriate obligation for a Transmission Planner to maintain a database of Generator Owner or Transmission Owner models. This is inconsistent with MOD-032-1 for jointly developed modeling data requirements and reporting procedures of the Transmission Planner and Planning Coordinator, as well as the requirement for Generator Owner or Transmission Owner to submit modeling data to its Transmission Planner and Planning Coordinator. Additionally, the proposed Part 1.6 omits the key reference to current (in-use) models intended to refer to those used for study. The Requirement R1, Part 1.4 should be revised to **remove the reference to a database**:

Process for Generator Owner or Transmission Owner to obtain model data from the its Transmission Planner's database for an existing Facility owned by the Generator Owner or Transmission Owner within 90 calendar days of receiving a written request.

3. Footnote 1 omits Planning Authority/Coordinator and is not consistent with the intent of the proposed Requirement R1. Footnote 1 should be revised to:

1 - Detailed EMT modeling requirements are developed by the Transmission Planner and its Planning Authority to ensure consistent EMT models are provided based on the types of studies being performed and the specific EMT simulation tools being used.

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 has attempted to contact the Standard Drafting Team to address some concerns regarding the modifications but has not received a response. Therefore, PG&E cannot support the modifications until those concerns are addressed.	
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	No
Document Name	
Comment	
At note 1 of R1, the term “Verification” only includes the static check between in-service equipment and model structure/parameters. However, each R2 to R6 requirement includes a “validation” aspect as part of the “verification” (2.4, 3.4, 4.4, 5.4, 6.4, and 6.5). To be consistent, the following text should be added at the end of note 1: “Verification may include a validation activity”.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS does not agree that EMT modeling is necessary for dynamic model verification or that the SAR has provided sufficient justification for this practice. Concerns for large-signal disturbance behavior are already being addressed by PRC-024 and the NERC “BPS-Connected Inverter-Based Resource Performance Reliability Guideline.” While these do not directly address modeling, they require that the type of behavior that was witnessed during the Blue Cut fire is mitigated. Because we are currently setting protection to be broad enough to ride through these disturbances, requiring EMT	

models in addition to positive sequence models would add significant cost and time to model verification without creating additional reliability. Additionally, as written, R1 applies to both synchronous and inverter based resources. Currently there are no EMT models available for synchronous generation as it has not been determined to be useful. For these reasons, EMT models should not be required for synchronous resources, and only required for inverter based resources on an as needed basis such as if the model response does not match the actual response from a system event.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

Footnote 2 states that “EMT model requirements are developed by the Transmission Planner.” Since this footnote references requirements, it should read “Transmission Planner and its Planning Coordinator” to be consistent with the language in R1.

Likes 0	
Dislikes 0	

Response

Shuying Zhen - GE - GE Wind - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

Many OEMs maintain user-defined models that are most applicable to their equipment. As OEMs do not develop the structure of generic models, the level of accuracy in product representation is limited. Recommend to add footnote to R1.1 stating “GOs can provide OEM user-defined models as acceptable positive sequence models since they are more accurate representations of the equipment.”

Likes 0	
Dislikes 0	

Response

Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters

Answer	No
Document Name	

Comment	
Comments: In MOD-026-1 and MOD-027-1, the TP only needs to provide information to the GO when the GO requests the information. Now, under MOD-026-2, the TP “shall jointly develop dynamic model requirements and processes” and the documentation “shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner” regardless of whether the information is actually requested by the GO or TO. As a vertically integrated utility, such processes do not add value equal to the administrative burden to the TP in creating, archiving, and tracking said processes. The concept of model interoperability (1.3.2) is a concept not well discussed in the standard or elsewhere. It is recommended either this concept be better supported or removed altogether. For the 1.2. requirement for Transmission Planners to have EMT specifications, this will add burden to those Transmission Planners who do not have IBRs or other devices covered under the proposed MOD-026-2 Requirements R4 or R5, yet would still be required to develop and maintain a specification for models that the Transmission Planner does not have in its footprint. The applicability for this requirement needs to be better tailored to allow the Transmission Planner to not fall under this requirement if it does not have such equipment that requires this. Furthermore, upon review of the SARs, none of the SARs propose any new EMT modeling requirements, so this R1.1.2 and R6 addition appears to be outside the scope of the SARs for the MOD-026/27 standard revisions.	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	No
Document Name	
Comment	
Footnote 2 states that “EMT model requirements are developed by the Transmission Planner.” Since this footnote references requirements, it should read “Transmission Planner and its Planning Coordinator” to be consistent with the language in R1.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Despite the efforts made in Draft 3 of MOD-026, SIGE does not support the inclusion of EMT modeling as there are no currently approved NERC EMT models.	

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	

It is unclear why the Planning Coordinator is being added to this requirement when the existing MOD-026 & 027 standards do not apply to this function. The Planning Coordinator is required to jointly develop dynamic model verification requirements and processes with the Transmission Planner but is not included as a recipient of the data in any of the subsequent requirements.

The time requirement for the TP to provide the dynamic model verification requirements and processes is not specified in R1.1 through R1.5.

The wording in R1.3 is unclear. It is also unclear why the PC is added to the parent requirement (R1) and not this sub-requirement (R1.3).

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	No
Document Name	
Comment	

At note 1 of R1, term “Verification” only includes the static check between in-service equipment and model structure/parameters. However, each R2 to R6 requirements include a “validation” aspect as part of the “verification” (2.4, 3.4, 4.4, 5.4, 6.4 and 6.5). To be consistent, the following text should be added at the end of note 1: “Verification may include a validation activity”.

Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	

Comment	
At note 1 of R1, term “Verification” only includes the static check between in-service equipment and model structure/parameters. However, each R2 to R6 requirements include a “validation” aspect as part of the “verification” (2.4, 3.4, 4.4, 5.4, 6.4 and 6.5). To be consistent, the following text should be added at the end of note 1: “Verification may include a validation activity”.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
R1.1 includes the language of R2-R5. R4 and R5 cover Inverter Based Resources. SRP strongly feels Inverter Based Resources should have separate standards.	
Likes 0	
Dislikes 0	
Response	
David Kwan - Ontario Power Generation Inc. - 4 - NPCC	
Answer	No
Document Name	
Comment	
Concur with NPCC RSC comments.	
Likes 0	
Dislikes 0	
Response	
Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
The SPP RTO recommends the drafting team consider removing the Planning Coordinator (PC) from the applicability section and Requirement R1 of the document. This is a redundant effort that can be addressed in the MOD-032 project per Requirement R1 (shown below). The drafting team should coordinate with the MOD-032 drafting team to ensure that proposed language aligns with the coordinated intent (which is the TP and PC coordinating to develop and maintaining model requirements and processes and making them available to the Generator Owner and Transmission Owner). From MOD-32: Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **1.1.** The data listed in Attachment 1. **1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s): **1.2.1.** Data format; **1.2.2.** Level of detail to which equipment shall be modeled; **1.2.3.** Case types or scenarios to be modeled; and **1.2.4.** A schedule for submission of data at least once every 13 calendar months. **1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
NRG still believes the requirements and process development leaves out the involvement of the GO thus the Transmission Entities have full right to push requirements onto the GO using tariff requirements. NRG would like to see actual division of responsibility assigned for the different sub sections of R1 in the standard directly. This will afford the GO to argue its case through the NERC standard. Right now, this requirement passes over this responsibility to the Planners. Currently, the TPs are using Tariff requirements to push Planning tasks onto the GO. GOs are not part of the transmission planning process and should not function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments. GOs therefore should not shoulder the burden of costs for these validation checks.	
Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

No. NRG still believes the requirements and process development leaves out the involvement of the GO thus the Transmission Entities have full right to push requirements onto the GO using tariff requirements. NRG would like to see actual division of responsibility assigned for the different sub sections of R1 in the standard directly. This will afford the GO to argue its case through the NERC standard. Right now, this requirement passes over this responsibility to the Planners. Currently, the TPs are using Tariff requirements to push Planning tasks onto the GO. GOs are not part of the transmission planning process and should not function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments. GOs therefore should not shoulder the burden of costs for these validation checks.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

: ITC has concerns with R1 and specifically with the requirement that the Transmission Planner and the Planning Coordinator jointly develop the dynamic model verification requirements and processes. With the Planning Coordinator not having any stake in the required work, they can place significant work and requirements on the Transmission Planner for the verification process making it extremely challenging for TPs to meet both the requirements and the timelines required of the standard.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.

Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	

The ISO/RTO Council's (IRC) Standards Review Committee (SRC) disagrees with the SDT's Time Horizon change to include only Long-Term Planning. This requirement was previously an Operations Planning requirement and there is no evidence in the record (or Technical Rationale) that supports why this is no longer a need. While we do support a Time Horizon change to include Long-Term Planning, we believe the Time Horizon should include both Long-Term Planning and Operations Planning. These models will be utilized in the Operations Planning realm as well as the Long-Term Planning realm going forward with the updates to FAC-011 and FAC-014 that become effective 4/1/2024. Therefore, the SRC requests the SDT modify the assigned Time Horizon to reflect both Operations Planning and Long-Term Planning.

Furthermore, the SRC is concerned by the use of "parameterization checks" in R1.3.1, as the Planning Coordinator (PC)/Transmission Planner (TP) is not the appropriate entity to specify or check model parameter values (i.e. parameterization) for equipment that is designed and owned by others (and potentially represented by user-defined models). The PC/TP may be able to check submitted evidence to ensure that a model parameter appropriately reflects a field setting or may be able to check overall model performance. However, use of the parameterization term in the standard would result in unintended compliance risk for the PC/TP if explicit parameterization criteria are not specified in the PC/TP requirements and processes. The SRC recommends that "model parameterization checks" be replaced with "model checks." This would cover all potential model acceptance criteria deemed appropriate by the PC/TP and not put a compliance obligation solely on parameterization checks.

Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
These changes will support system reliability with verification of synchronous generation below the current approved versions 100 MVA and additional inverter based resources.	
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	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed language, however feels the 90 day requirement under R1.6 is duplicative to R8. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed language, however feels the 90 day requirement under R1.6 is duplicative to R8. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
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 language proposed for MOD-026-2 R1.	
Likes 0	
Dislikes 0	
Response	

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

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters	
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	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
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	
Glen Farmer - Avista - Avista Corporation - 5	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
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	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Roethemeyer - Vistra Energy - 5	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
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	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 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	
Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment

“See comments submitted by the Edison Electric Institute"

Likes 0	
Dislikes 0	

Response

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	

Comment

The Standard Drafting team has posted a redline with red and blue text. It’s unclear if these redlines are from Draft 1 or the last approved version. We request that the Standard Drafting Team for this project adopt the same method of posting a redline from at least the last approved version of the Standard as it’s unclear as to what is being proposed as far as revisions are concerned. We also do not understand why NERC SDTs post different types of redlines, e.g., some SDTs post redlines back to last approved version while other do not. This SDT is using two colors on a third draft. If NERC could adopt a standardized process amongst ballots it would be helpful.

Likes 0	
Dislikes 0	

Response

2. Do you agree with the language proposed in MOD-026-2 Requirements R2 and R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

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

R2.3: MOD-026-2 should not have a requirement for models to contain excitation limiters and Protection System settings. This information is already provided in PRC-019 and PRC-024.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

R2.3: MOD-026-2 should not have a requirement for models to contain excitation limiters and Protection System settings. This information is already provided in PRC-019 and PRC-024.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Remove TO from M3 as R3 only talks to the GO.

Likes 0	
Dislikes 0	

Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
No. Limiters and Protection are not dynamic model elements; machine and control characteristics are. Currently the PRC standards define a no trip zone for GOs for the different elements. These criteria should be used by the Planners to establish the modeling field instead of trying to model every protection. This will afford a good conservatism for reliability and also flexibility for the GOs to set relays without needing to cycle through this modeling requirement.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Limiters and Protection are not dynamic model elements; machine and control characteristics are. Currently the PRC standards define a no trip zone for GOs for the different elements. These criteria should be used by the Planners to establish the modeling field instead of trying to model every protection. This will afford a good conservatism for reliability and also flexibility for the GOs to set relays without needing to cycle through this modeling requirement.	
Likes 0	
Dislikes 0	
Response	
David Kwan - Ontario Power Generation Inc. - 4 - NPCC	
Answer	No
Document Name	
Comment	
Concur with NPCC RSC comments.	
Likes 0	

Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

Since MOD-026/027 models are used in Positive Seq. software to validate the performance of the facility/asset for voltage and frequency excursions, SRP believes inclusion of O/U Voltage and O/U Frequency elements outlined in R2.3 and R3.3 is a common practice and should be a part of the model verification and validation.

However, we have not seen an out of Step protection included in Positive Seq. model for a synchronous generator from OEM. We can understand the rationale for including this type of protection in the model for simulating stable power swings (and 3P/1LG fault conditions) and verifying if the generator maintains synchronization, however, that will require detailed guidelines and recommendations that is currently lacking. Therefore, SRP recommends removing the out of step protection in R2.3 since it is already captured in PRC-026 to demonstrate asset response during Unstable/Stable power swings.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

At section 3.3, delete sentence: “In addition, model(s) representing enabled prime mover over- and under-speed trip functions that directly trip the prime mover/generator;”, because it is redundant with the previous sentence. Over- and under-frequency protection is the same than over- and under-speed protection. Note that requirements for other resources (2.3, 4.3, 5.3 and 6.3) do not include such repetition. Leaving the repetition may lead to confusion.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	No

Document Name	
Comment	
At section 3.3, delete sentence: “In addition, model(s) representing enabled prime mover over- and under-speed trip functions that directly trip the prime mover/generator;”, because it is redundant with the previous sentence. Over- and under-frequency protection is the same than over- and under-speed protection. Note that requirements for other resources (2.3, 4.3, 5.3 and 6.3) do not include such repetition. Leaving the repetition may lead to confusion.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
The wording of the requirements is fine in general. However, the Planning Coordinator is added to Requirement 1 to, along with the Transmission Planner, develop dynamic model verification requirements and processes. In R2 & R3, the Planning Coordinator is not included as a recipient of the models. As stated in the response to R1, it is unclear why the Planning Coordinator is not included in these requirements if it was added to Requirement 1 in this modified standard proposal.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy suggests sections 2.3 and 3.3 describing limiters and protection should be removed. Inclusion of these sections infringes on other standards such as MOD-032 and PRC-024.	
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 does not agree with the proposed language for Requirement R2 and R3. The NAGF requests that the language in Requirements 2.3 and 3.3 describing limiters and protection should be removed. Inclusion of these sections infringes on and overlaps other standards such as PRC-019 and PRC-024.	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
We support the subpoints in 2.1, 2.2, 2.3, 3.1, 3.2, and 3.3. However, the generators are able to provide the best available models to the Transmission Planner, but the TP would need to validate the model and provide changes back to the Generator Owner and Transmission Owner.	
Likes 0	
Dislikes 0	
Response	

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	No
Document Name	
Comment	
R2.2/R2.3 and R3.2/R3.3 should be removed and instead reference models, format, and level of detail as stated by Transmission Planner and its Planning Coordinator in R1.1.	
Likes 0	
Dislikes 0	
Response	

Daniel Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	
• Regarding the limiter and protection requirements in R2 and R3, the standard should provide more guidance. Are all limiters included (over/under excitation, V/Hz, stator current, etc) which may not all be defined in PSS/E or other modeling software. Most models seem to only include over excitation limiters (OEL) which is important for determining field forcing capabilities and stability. • We disagree with adding the protection parameters into the model. There is some overlap with MOD-032 and in most cases we are already providing voltage, frequency, and out of step protection parameters to the Transmission Planners and ISOs. The current language in MOD-026 would require generator owners to update all the reports and essentially perform the same work twice.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE requests clarification on the language used to include limiters and tripping elements, as requested models typically do not include these elements.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation does not have additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
R2.2/R2.3 and R3.2/R3.3 should be removed and instead, reference models, format, and level of detail, as stated by Transmission Planner and its Planning Coordinator, as found in R1.1. Additionally, for clarification purposes, we ask the following questions: For Generation, what kind of model representation is expected for enabled Protection Systems and over/under speed trip functions? Would it be just the settings of the Protection System and over/under speed elements or would something else be required?	
Likes 0	

Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS appreciates the changes that the STD has made between Draft 2 and Draft 3. For Requirement 2, Part 2.3 and Requirement 3, Part 3.3, AZPS requests that the SDT add clarification regarding what is meant by direct trip of the prime mover, including clarification of which trips are to be addressed or by providing diagrams such as those included in the current versions of PRC-025 and PRC-027. For Requirement 2, Part 2.3 and Requirement 3, Part 3.3 AZPS does not agree that modeling limiters and protection systems for prime movers for generator/synchronous condensers should be included as PRC-019 already ensures that limiters and protection systems are coordinated to ensure they operate as intended and are adequate for the intended application. For this reason, creating generator protection models from protection settings would still be a significant amount of work with very little reliability benefit.	
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	No
Document Name	
Comment	
In section 3.3, delete the sentence: “In addition, model(s) representing enabled prime mover over- and under-speed trip functions that directly trip the prime mover/generator;”, because it is redundant with the previous sentence. Over- and under-frequency protection is the same as over- and under-speed protection. Note that requirements for other resources (2.3, 4.3, 5.3, and 6.3) do not include such repetition. Leaving the repetition may lead to confusion.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment	
Constellation does not have additional comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: R2.3: MOD-026-2 should not have a requirement for models to contain excitation limiters and Protection System settings. This information is already provided in PRC-019 and PRC-024.	
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 has attempted to contact the Standard Drafting Team to address some concerns regarding the modifications but has not received a response. Therefore, PG&E cannot support the modifications until those concerns can be addressed.	
Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by Tacoma Power.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF suggests sections 2.3 and 3.3 describing limiters and protection should be removed. Inclusion of these sections infringes on other standards such as MOD-032 and PRC-024.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
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	
Sections 2.3 and 3.3 describing limiters and protection should be removed. Inclusion of these sections infringes on other standards such as PRC-019 and PRC-024.	
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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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 language in MOD-026-2 R2.3. Specifically, Tacoma Power does not agree with keeping the out-of-step protection element in-scope of synchronous generation modeling, because it's not clear how out-of-step condition would be simulated in the field and validated. Additionally, current modeling programs do not have models for all the proposed protection system elements in R2.3. Implementation of R2.3 will depend on future development of models, which poses a compliance risk if these models cannot be generated.	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3	
Answer	No
Document Name	
Comment	
Entergy recommends that the wording for R2 be modified to simply be models represented required data of as defined by the TP/PC in R1.	

For R2&R3, Entergy recommend SDT to provide more clarification on: How do these excitation system limiters and generator protection systems aligned with MOD-032 modelling requirements for generators?

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

The R2.3 statement, “Protection Systems that trip the prime mover or generator/synchronous condenser either directly or via lockout or auxiliary tripping relays,” is inconsistent with the subsequent, “Protection Systems that shall be modeled include phase over- and under-voltage, out-of-step, and volts per hertz protection.” That is, the first criterion pulls all Protection System relays in-scope, while the second one indicates that models need be developed for just a few.” The requirement should be rewritten to call for models for, “the following Protection System relays,” then list the ones that the SDT wants. A similar clarification is needed for R3.3.

The R3.4 requirement to validate all R3.2 models should exclude, “other controls which impact the dynamic active power or frequency performance,” where they are of a protective nature. A fossil unit with 5% droop, for example, may have a limiter that allows the 0.67% step-increase in power resultant from a 25 mHz drop in grid frequency, but truncates the 6.7% jump corresponding to a 250 mHz disturbance, lest the unit trip (e.g. for high/low drum level) or suffer a high cumulative fatigue damage incident due to vastly exceeding the OEM’s max-recommended ramp rate.

CTGs often have a ramp rate limiter, and pushing units in MOD-026 tests to show its impact could have a number of unexpected negative consequences including emissions permit violations and (for downward commands) flame-out.

Demonstrating the effect of protective functions by intentionally hitting them during tests is in general excessively risky.

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

For R2: the requirements R2.2, and R2.3 should be removed and replaced by the following statement “The verified model(s) and accompanying information shall meet the requirements, format, and level of detail as stated by TP/PC in the R1.1.

For R3: the requirements R3.2, and R3.3 should be removed and replaced by the following statement “The verified model(s) and accompanying information shall meet the requirements, format, and level of detail as stated by TP/PC in the R1.1.

Manitoba Hydro (MH) believes it is up to the TP/PC (based on their experience) to determine the required minimum modeling requirements and level of the modeling details required for the protection and control. These requirements shall be clearly stated in the R1.1.

The level of detail and minimum requirements may change based on the type of study and studies issues. The model requirements for the new facilities may differ from the in-service facilities and some in-service facilities may require a different level of detail. Therefore, the model(s) level of detail should be left to the TP/PC.

Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

1. Entergy recommends that the wording for R2 be modified to simply be models represented required data of as defined by the TP/PC in R1.
2. For R2&R3, Entergy recommend SDT to providemore clarification on: How do these excitation system limiters and generator protection systems aligned with MOD-032 modelling requirements for generators?

Likes 0	
Dislikes 0	
Response	

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters

Answer	No
Document Name	

Comment

The scope of generator modeling has been expanded to include some limiters and protections. While some of these additions are rather straightforward to implement in a model, others such as modeling Out-of-Step Relays (OOSR) can present a significant challenge, based on BC Hydro’s experience.

BC Hydro uses the so-called single blinder scheme, wherein the out of step condition is detected by tracking the path of the positive sequence impedance trajectory that passes through the zone. Such OOSR do not map out directly to the standardized models available for modeling. So far, BC Hydro has been unable to find a protection model that can be used to correctly model such OOSR.

If the R2 language is to be maintained to include OOSR in scope, BC Hydro recommends that the SDT work with the software vendors and technical community (e.g., WECC MVS) to obtain their endorsement on the current implementation timelines for R2-R5 (i.e., maintaining the existing facilities’ 10-

year reoccurring periodicity and allowing a 3-year timeline for newly applicable facilities), ensuring sufficient lead time is allocated for developing suitable OOSR models.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP’s negative ballot on MOD-026-2 is driven by the following concerns and recommendations.

AEP does not agree with the inclusion of models representing Protection Systems of synchronous generating units as stated in R2.3 and R3.3:

1. MOD-032 allows the TP and PC to request protection system data and modeling if it is deemed necessary. MOD-026 is supposed to be a model verification/validation standard. It should not be expanded into a data collection standard and thereby not only cause compliance duplication with MOD-032, but force collection of data that the TP and PC may well regard as unnecessary. Validation (as “validation” is defined in the standard) of protection function modeling is already acknowledged as not feasible. As with the collection of any and all data, the collection of protection modeling data implies its verification and thus verification may and should be left to MOD-032.

2. R2.3 and R3.3 introduce further compliance duplication by requiring the Generator Owner to verify generator protection models whose settings data is already verified through the scope of obligations within PRC-019, PRC-024, PRC-026, and PRC-027. When considered in their entirety, these standards, in requiring verification of protection system settings against certain stipulated criteria designed to address conditions and events that could negatively impact BES reliability, serve to meet the SDT’s intent.

3. In distinct contrast to IBR protection and control as seen in recent disturbance event tripping and runback, the requested protection function modeling of synchronous generation has not been found to worsen disturbance events in any significant way. Moreover, also in distinct contrast to IBR protection and control, synchronous generation protection has accumulated a great deal of theory and experience in application over many decades. This has eliminated nearly all risk in its application. As long as setting coordination and verification is assured via these other standards, there is no meaningful gain to reliability in requiring the collection of this data in MOD-026-2.

Therefore, for the reasons 1 through 3 above, we do not believe the proposed inclusion of protection model data verification and collection in MOD-026 would result in meaningful contribution to improving the reliability of the BES.

4. Further rationale for removing the listed protective functions are as follows:

• Out-of-step – Not universally applied on all synchronous units. There are other more straightforward means to remove unstable units from simulations (there is a check box option in PSS/E, for example). It is not necessary to add this model in simulations.

• Volts per hertz – Generally, a limiter function is coordinated with trip and in many cases the trip function is active only while the unit is off-line in start-up or shutdown. With possible exception of UFLS studies where low frequency conditions are intentionally produced, it is not generally necessary and there are time-based V/Hz constraints on UFLS program settings in PRC-006 to avoid V/Hz limiter activation. Thus, this protection is unnecessary to model. There is no limiter function model in PSS/E; it is trip or monitor only.

AEP disagrees with the inclusion of “prime mover” within 2.3, as none of the devices specified in 2.3 would directly trip the prime mover.

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed changes to R2 and R3.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
Likes 0	

Dislikes 0	
Response	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Oncor agrees that including more model components, including protection functions, will be better for more accurate simulations.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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	

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
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	

Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
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	

Robert Follini - Avista - Avista Corporation - 3	
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
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	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
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	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	

Document Name	
Comment	
“See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the language proposed in MOD-026-2 Requirements R4 and R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

For R4: the requirements R4.2, and R4.3 should be removed and replaced by the following statement “The verified model(s) and accompanying information shall meet the requirements, format, and level of detail as stated by TP/PC in the R1.1.

For R5: the requirements R5.2, and R5.3 should be removed and replaced by the following statement “The verified model(s) and accompanying information shall meet the requirements, format, and level of detail as stated by TP/PC in the R1.1.

Manitoba Hydro believes it is up to the TP/PC (based on their experience) to determine the required minimum modeling requirements and level of the modeling details required for the protection and control. These requirements shall be clearly stated in the R1.1.

The level of detail and minimum requirements may change based on the type of study and studies issues. The model requirements for the new facilities may differ from the in-service facilities and some in-service facilities may require a different level of detail. Therefore, the model(s) level of detail should be left to the TP/PC.

If the purpose of Attachment 1 is to provide the information related to model verification periodicity, then the Unit model verification frequency excursion criteria specified under NOTE 1 seems out of place. This can be placed under a separate table instead of placed under Attachment 1.

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

Sections 4.3 and 5.3 describing limiters and protection should be removed. Inclusion of these sections infringes on other standards such as PRC-019 and PRC-024.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF suggests sections 2.3 and 3.3 describing limiters and protection should be removed. Inclusion of these sections infringes on other standards such as MOD-032 and PRC-024.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: R4.3/R5.3: MOD-026-2 should not have a requirement for models to contain excitation limiters and Protection System settings. This information is already provided in PRC-019 and PRC-024.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Constellation does not have additional comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

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

For Requirement 4, Part 4.3 and Requirement 5, Part 5.3, AZPS does not agree that modeling limiters and protection systems for prime movers of generator/synchronous condensers should be required as PRC-019 already ensures that limiters and protection systems are coordinated to ensure they operate as intended and are adequate for the intended application. For this reason, creating additional models would create additional work with very little reliability benefit.

For Requirements 4 & 5, AZPS also requests that the SDT clarify which devices are the responsibility of the GO and which devices are the responsibility of the TO. For example, it would seem that the inverter based resources are the responsibility of the GO, and devices such as FACTS and VSC HVDC are the responsibility of the TO.

Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

R4.2/R4.3 and R5.2/R5.3 should be removed and instead reference models, format, and level of detail as stated by Transmission Planner and its Planning Coordinator in R1.1

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation does not have additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	No
Document Name	
Comment	

R4.2/R4.3 and R5.2/R5.3 should be removed and instead reference models, format, and level of detail as stated by Transmission Planner and its Planning Coordinator in R1.1.

Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
We support the subpoints in 4.1, 4.2, 4.3, 5.1, 5.2, and 5.3. However, the generators are able to provide the best available models to the Transmission Planner, but the TP would need to validate the model and provide changes back to the Generator Owner and Transmission Owner.	
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 does not agree with the proposed language for Requirement R4 and R5. The NAGF requests that the language in Requirements 4.3 and 5.3 describing limiters and protection should be removed. Inclusion of these sections infringes on and overlaps other standards such as PRC-019 and PRC-024. *In addition, the NAGF notes that NERC needs to provide an official definition for Inverter-Base Resources to ensure constancy across applicable Reliability Standards.*	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No

Document Name	
Comment	
NV Energy suggests sections 2.3 and 3.3 describing limiters and protection should be removed. Inclusion of these sections infringes on other standards such as MOD-032 and PRC-024.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
The wording of the requirements is fine in general. However, the Planning Coordinator is added to Requirement 1 to, along with the Transmission Planner, develop dynamic model verification requirements and processes. In R4 & R5, the Planning Coordinator is not included as a recipient of the models. As stated in the response to R1, it is unclear why the Planning Coordinator is not included in these requirements if it was added to Requirement 1 in this modified standard proposal.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
R4 and R5 cover Inverter Based Resources. SRP strongly feels Inverter Based Resources should have separate standards.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	

Answer	No
Document Name	

Comment

Regarding R4.3, 4.4, 5.3, and 5.4, the addition of limiters and protection into models is repeating the purpose of the PRC standards. It would be best to research if the planners to setup model boundaries based on these standard criteria rather than try to model each machine.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Regarding R4.3, 4.4, 5.3, and 5.4, the addition of limiters and protection into models is repeating the purpose of the PRC standards. It would be best to research if the planners to setup model boundaries based on these standard criteria rather than try to model each machine.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

ITC has concern with R4 if the expectation is that the FACTS devices are tested through the majority or all of the range of capability. Certain FACTs devices are installed to address significant system conditions and may not be able to be tested at all output levels within the capability of the device (R4.4). A clarification that the staged tests are not required at all output levels will alleviate this concern.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
R4.3/R5.3: MOD-026-2 should not have a requirement for models to contain excitation limiters and Protection System settings. This information is already provided in PRC-019 and PRC-024.	
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	
R4.3/R5.3: MOD-026-2 should not have a requirement for models to contain excitation limiters and Protection System settings. This information is already provided in PRC-019 and PRC-024.	
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	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Entergy recommends the wording for R4 & R5 be modified to simply be models represented required data as defined by the TP/PC in R1	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	

Entergy recommends the wording for R4 & R5 be modified to simply be models represented required data as defined by the TP/PC in R1.	
Likes 0	
Dislikes 0	
Response	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
Oncor agrees that including more model components, including protection functions, will be better for more accurate simulations.	
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 agrees with the proposed modifications.	
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	
Please provide clarification on the intent of why R3 only includes GOs however in M3 it includes GOs and TOs.	

Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the NAGF comments that NERC needs to provide an official definition for Inverter-Based Resources to ensure consistency across applicable Reliability Standards.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the NAGF comments that NERC needs to provide an official definition for Inverter-Based Reousrces to ensure consistency across applicable Reliability Standards.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the NAGF comments that NERC needs to provide an official definition for Inverter-Based Resources to ensure consistency across applicable Reliability Standards.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the NAGF comments that NERC needs to provide an official definition for Inverter-Based Resources to ensure consistency across applicable Reliability Standards.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	Yes
Document Name	

Comment

Please provide clarification on the intent of why R3 only includes GOs however in M3 it includes GOs and TOs.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	Yes
Document Name	

Comment

Please provide clarification on the intent of why R3 only includes GOs however in M3 it includes GOs and TOs.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

EEI supports the proposed changes to R4 and R5.

Likes 0	
Dislikes 0	

Response

David Kwan - Ontario Power Generation Inc. - 4 - NPCC	
Answer	Yes
Document Name	
Comment	
Concur with NPCC RSC comments.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters	
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	
John Pearson - ISO New England, Inc. - 2	
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	
Glen Farmer - Avista - Avista Corporation - 5	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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	

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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
Answer	
Document Name	
Comment	
Abstain. R4 and R5 are only for inverter based resources.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the language proposed in MOD-026-2 Requirement R6? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

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

Requirement 6.1 requires the GO/TO to obtain an attestation from the OEM to verify the IBR model structure with respect to the supplied equipment. We have several concerns with this approach. Our concerns and subsequent recommendation are enumerated below:

1. The devices enumerated in R6.1 are often sourced from different vendors; therefore, it is highly likely that multiple attestations would be necessary to satisfy this requirement. Consider the following example for a hypothetical wind generation facility:

a. Inverters are sourced from Vendor ABC.
b. The power plant controller is either a PLC or DCS sourced from Vendor DEF.
c. Wind turbine control PLC's (a.k.a. auxiliary control devices) are supplied by the wind turbine manufacturer Vendor GHI.

2. The OEM can only attest as to what was provided to the GO/TO and not to what is currently installed. The OEM has no way of knowing whether the supplied equipment was modified by third-party after it was provided to the GO/TO. In the example identified above, devices supplied by Vendors DEF and GHI are highly configurable and modifiable. Thus, it brings into question the relevancy of any attestation(s) provided by the OEM for those cases.

3. Depending on the modeling software used, the OEM may or may not have a working knowledge of the modeling software. It is possible that the OEM would lack the in-house expertise to provide an attestation to verify the structure of the model without additional external resources. This has the potential to further increase any associated costs.

4. For existing facilities commissioned after 1/1/2023 and prior to the compliance date for R6, requiring an attestation from the OEM that the model is accurate is overly burdensome to the GO/TO.

a. As the OEM is not a responsible entity, they are not subject to the requirements of this standard. Therefore, if an attestation was not provided at the time the equipment was procured, the GO/TO will likely need to pay the OEM to review the structure of the model and provide an attestation.
b. Requiring the GO/TO to obtain an attestation from an entity that has no requirement to provide said information places all the responsibility and none of the authority on the GO/TO vis-à-vis compliance with R6.1.

5. For new facilities built or commissioned after the compliance date for R6, the GO/TO will need to contractually obligate the OEM(s) to provide the attestation(s) proposed in R6.1. This will likely increase the associated project costs.

It is our recommendation that R6.1 be modified so that the verification of the model structure is at the discretion of the GO/TO provided that the chosen method satisfies the Requirements identified in R1. It is our opinion that an engineering review by the GO/TO would be an equally acceptable method for verifying the structure of the model.

In short, we believe that an attestation from the OEM should be one acceptable method for verification, but not the only method.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	

Since the standard is not being proposed as retroactive for existing units and has up to a 10-year implementation period, it is unclear why R6, Part 6.2 essentially makes device tests optional. Rather than merely requiring documentation of the reason that device tests are unavailable, Part 6.2 should establish objective, auditable criteria (or some other oversight process) for when it is acceptable for a device test to be unavailable.

The SRC appreciates the discussion of large signal disturbances in the technical rationale; however, the SRC recommends that R6, Parts 6.2 and 6.6 be more specific about how many and what type of large disturbance tests are required. As written, it seems that a single large disturbance test could potentially be interpreted as satisfying the requirement, and it is not clear if that is the SDT's intent for these requirements.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	

Buckeye supports the comments made by ACES:

Requirement 6.1 requires the GO/TO to obtain an attestation from the OEM to verify the IBR model structure with respect to the supplied equipment. We have several concerns with this approach. Our concerns and subsequent recommendation are enumerated below:
1. The devices enumerated in R6.1 are often sourced from different vendors; therefore, it is highly likely that multiple attestations would be necessary to satisfy this requirement. Consider the following example for a hypothetical wind generation facility:
a. Inverters are sourced from Vendor ABC.

b. The power plant controller is either a PLC or DCS sourced from Vendor DEF.
c. Wind turbine control PLC’s (a.k.a. auxiliary control devices) are supplied by the wind turbine manufacturer Vendor GHI.

In this example of a hypothetical IBR facility, under the proposed Requirement 6.1, the GO would be required to obtain an attestation from 3 separate OEMs for 3 distinct types of equipment.
2. The OEM can only attest as to what was provided to the GO/TO and not to what is currently installed. The OEM has no way of knowing whether the supplied equipment was modified by third-party after it was provided to the GO/TO. In the example identified above, devices supplied by Vendors DEF and GHI are highly configurable and modifiable. Thus, it brings into question the relevancy of any attestation(s) provided by the OEM for those cases.
3. Depending on the modeling software used, the OEM may or may not have a working knowledge of the modeling software. It is possible that the OEM would lack the in-house expertise to provide an attestation to verify the structure of the model without additional external resources. This has the potential to further increase any associated costs.
4. For existing facilities commissioned after 1/1/2023 and prior to the compliance date for R6, requiring an attestation from the OEM that the model is accurate is overly burdensome to the GO/TO.
a. As the OEM is not a responsible entity, they are not subject to the requirements of this standard. Therefore, if an attestation was not provided at the time the equipment was procured, the GO/TO will likely need to pay the OEM to review the structure of the model and provide an attestation.
b. Requiring the GO/TO to obtain an attestation from an entity that has no requirement to provide said information places all the responsibility and none of the authority on the GO/TO vis-à-vis compliance with R6.1.
5. For new facilities built or commissioned after the compliance date for R6, the GO/TO will need to contractually obligate the OEM(s) to provide the attestation(s) proposed in R6.1. This will likely increase the associated project costs.
It is our recommendation that R6.1 be modified so that the verification of the model structure is at the discretion of the GO/TO provided that the chosen method satisfies the Requirements identified in R1. It is our opinion that an engineering review by the GO/TO would be an equally acceptable method for verifying the structure of the model.
In short, we believe that an attestation from the OEM should be one acceptable method for verification, but not the only method.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

: ITC has concern with R6 if the expectation is that the FACTS devices are tested through the majority or all of the range of capability. Certain FACTs devices are installed to address significant system conditions and may not be able to be tested at all output levels within the capability of the device (R6.5). A clarification that the staged tests are not required at all output levels will alleviate this concern.

Likes 0	
Dislikes 0	

Response

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

Answer	No

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
R6 cover Inverter Based Resources. SRP strongly feels Inverter Based Resources should have separate standards.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
The wording of the requirements is fine in general. However, the Planning Coordinator is added to Requirement 1 to, along with the Transmission Planner, develop dynamic model verification requirements and processes. In R6, the Planning Coordinator is not included as a recipient of the models. As stated in the response to R1, it is unclear why the Planning Coordinator is not included in these requirements if it was added to Requirement 1 in this modified standard proposal.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No

Document Name	

Comment

NV Energy does not agree with the Requirement 6.1. as it relates to attestations from the original equipment manufacturer (OEM). First, it is the registered entities responsibility to ensure that model represents that actual equipment's configuration. An attestation from the OEM adds no reliability value as the OEM does not have the same motivations as a registered entity. The reliability value arises from a model that accurately represents the control configuration of the equipment. Second, the requirement is indirectly applying a NERC Standard requirement to organizations that are not identified as entities that are required to be registered with NERC pursuant to the NERC Rules of Procedure. Third, do Transmission Planners need or even want an attestation that the model matches the equipment's configuration?

It seems that the intention of the requirement is to ensure that model matches the actual equipment configuration. If this is in fact the case, then the requirement should be simply written as follows: "A responsible entity shall ensure that the model accurately represents the actual control configuration of the equipment." or something to that effect. Then in the technical rational the SDT could provide examples of how an entity could demonstrate compliance with the requirement, including OEM attestations, comparison reports, et cetera. Writing the requirement in this manner does not limit the possibilities of how a responsible entity can verify that the model matches the actual equipment configuration.

Further, NV Energy recommends that R6 should be reworded such that TPs can identify and then request an EMT model for facilities that are a risk.

Reasons for exclusion:

1. EMT modeling for every BES facility will create an undue burden and expense for GOs, TOs and TPs.

2. EMT modeling software requires specialized computer hardware for analysis and is expensive.

3. EMT software analysis requires a unique set of engineering skills and requires much training.

4. There is no evidence from TPs that every facility has a need for an EMT model.

5. Not all facilities have recording equipment installed and configured to capture large signal disturbance events and the facility response. This means more equipment and manpower costs to purchase, install and maintain.

6. There is no way to stage a large signal disturbance system test. If one could be derived, it would likely be considered a BES reliability risk by the TP and RC and not allowed.

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 requests the SDT to consider removing Requirement R6 from the standard altogether or rewording R6 such that TPs can identify and then request an EMT model for facilities that are a risk.

Reasons for exclusion:

1. *EMT modeling for every BES facility will create an undue burden and expense for GOs, TOs and TPs.*
2. *EMT modeling software requires specialized computer hardware for analysis and is expensive.*
3. *EMT software analysis requires a unique set of engineering skills and requires much training.*
4. *There is no evidence from TPs that every facility has a need for an EMT model.*

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE does not support Requirement 6 as stated, CEHE recommends the Planning Coordinator (PC), in coordination with the Transmission Planner (TP), should verify the EMT models. CEHE does not have the tools/expertise currently for EMT model verification.

CEHE suggests clarification on the terminology “review”, “verify” and “validate” as these are used interchangeably. It is important for these terms to be clearly understood throughout the standard and used as intended.

CEHE seeks clarification of Required Action for R6 for those that meet exemption on Row Number 13 in Attachment 1 regarding the information to include in the “written statement.” If an entity meets the exception under item 13, what is the expectation for the required action. Is a written statement to the Transmission Planner required and what should be included in the written statement?

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

As a Generator Owner and Transmission Owner SIGE will continue to provide requested model data, but at this time there are no NERC approved EMT models with limited software/expertise.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
There are existing projects that fall under the requirements of R6 that have IBR manufacturers that are obsolete or no longer in business, and therefore an OEM based attestation or model does not exist and is unobtainable. NEE recommends a more general exclusion for existing IBR resources that do not have the means to create a PSCAD model due to these limitations.	
Likes 0	
Dislikes 0	
Response	
Shuying Zhen - GE - GE Wind - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
It is not feasible to represent all controls and protections in the models and some are not relevant in EMT studies, such as converter start-up sequences. Recommend to change language to "The attestation shall include the equipment make, model number, software/firmware version number, and confirmation that ***pertinent*** *inverter control modes, control blocks, and protections are represented in the model." instead of "all inverter control modes…".*	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	

Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation does not agree with the addition of EMT models due to the limited number of subject matter experts in the industry, equipment manufacturers and vendors that are able to implement the requirements in this standard as stated in the implementation plan. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	

Comment	
For Requirement 6, AZPS also requests that the SDT clarify which devices are the responsibility of the GO and which devices are the responsibility of the TO.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation does not agree with the addition of EMT models due to the limited number of subject matter experts in the industry, equipment manufacturers and vendors that are able to implement the requirements in this standard as stated in the implementation plan. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

Requirement 6.1 requires the GO/TO to obtain an attestation from the OEM to verify the IBR model structure with respect to the supplied equipment. We have several concerns with this approach. Our concerns and subsequent recommendation are enumerated below:
1. The devices enumerated in R6.1 are often sourced from different vendors; therefore, it is highly likely that multiple attestations would be necessary to satisfy this requirement. Consider the following example for a hypothetical wind generation facility:
a. Inverters are sourced from Vendor ABC.
b. The power plant controller is either a PLC or DCS sourced from Vendor DEF.
c. Wind turbine control PLC's (a.k.a. auxiliary control devices) are supplied by the wind turbine manufacturer Vendor GHI.In this example of a hypothetical IBR facility, under the proposed Requirement 6.1, the GO would be required to obtain an attestation from 3 separate OEMs for 3 distinct types of equipment.
2. The OEM can only attest as to what was provided to the GO/TO and not to what is currently installed. The OEM has no way of knowing whether the

supplied equipment was modified by third-party after it was provided to the GO/TO. In the example identified above, devices supplied by Vendors DEF and GHI are highly configurable and modifiable. Thus, it brings into question the relevancy of any attestation(s) provided by the OEM for those cases.
3. Depending on the modeling software used, the OEM may or may not have a working knowledge of the modeling software. It is possible that the OEM would lack the in-house expertise to provide an attestation to verify the structure of the model without additional external resources. This has the potential to further increase any associated costs.
4. For existing facilities commissioned after 1/1/2023 and prior to the compliance date for R6, requiring an attestation from the OEM that the model is accurate is overly burdensome to the GO/TO.
a. As the OEM is not a responsible entity, they are not subject to the requirements of this standard. Therefore, if an attestation was not provided at the time the equipment was procured, the GO/TO will likely need to pay the OEM to review the structure of the model and provide an attestation.
b. Requiring the GO/TO to obtain an attestation from an entity that has no requirement to provide said information places all the responsibility and none of the authority on the GO/TO vis-à-vis compliance with R6.1.
5. For new facilities built or commissioned after the compliance date for R6, the GO/TO will need to contractually obligate the OEM(s) to provide the attestation(s) proposed in R6.1. This will likely increase the associated project costs.
It is our recommendation that R6.1 be modified so that the verification of the model structure is at the discretion of the GO/TO provided that the chosen method satisfies the Requirements identified in R1. It is our opinion that an engineering review by the GO/TO would be an equally acceptable method for verifying the structure of the model.
In short, we believe that an attestation from the OEM should be one acceptable method for verification, but **not the only method**.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

BPA agrees that R6 and its sub requirements for IBR units, validation procedures, and documentation for improving EMT model quality are sound. BPA does not agree with the timing for inclusion of this requirement. BPA believes that best practices for EMT studies should be established first, before creating a requirement within the standards to validate EMT models. BPA recognizes that in March 2023 NERC approved an EMT Reliability Guideline as Part 1 of a two-part series. BPA believes that this guideline should have been Part 2, not Part 1. Once the next guideline is produced and released that specifically address how and when to conduct studies to mitigate the target reliability risks, the industry would be better equipped to respond to R6.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF does not agree with the Requirement 6.1. as it relates to attestations from the original equipment manufacturer (OEM). First, it is the registered entities responsibility to ensure that model represents that actual equipment's configuration. An attestation from the OEM adds no reliability value as the OEM does not have the same motivations as a registered entity. The reliability value arises from a model that accurately represents the control configuration of the equipment. Second, the requirement is indirectly applying a NERC Standard requirement to organizations that are not identified as entities that are required to be registered with NERC pursuant to the NERC Rules of Procedure. Third, do Transmission Planners need or even want an attestation that the model matches the equipment's configuration?

It seems that the intention of the requirement is to ensure that model matches the actual equipment configuration. If this is in fact the case, then the requirement should be simply written as follows: "A responsible entity shall ensure that the model accurately represents the actual control configuration of the equipment." or something to that effect. Then in the technical rational the SDT could provide examples of how an entity could demonstrate compliance with the requirement, including OEM attestations, comparison reports, et cetera. Writing the requirement in this manner does not limit the possibilities of how a responsible entity can verify that the model matches the actual equipment configuration.

Further the MRO NSRF recommends that R6 should be reworded such that TPs can identify and then request an EMT model for facilities that are a risk.

Reasons for exclusion:

1. EMT modeling for every BES facility will create an undue burden and expense for GOs, TOs and TPs.

2. EMT modeling software requires specialized computer hardware for analysis and is expensive.

3. EMT software analysis requires a unique set of engineering skills and requires much training.

4. There is no evidence from TPs that every facility has a need for an EMT model.

5. Not all facilities have recording equipment installed and configured to capture large signal disturbance events and the facility response. This means more equipment and manpower costs to purchase, install and maintain.

6. There is no way to stage a large signal disturbance system test. If one could be derived, it would likely be considered a BES reliability risk by the TP and RC and not allowed.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

Oncor agrees that reviewing EMT models along with positive sequence dynamic models will enhance model accuracy. However, it will be very difficult and potentially resource intensive to build and maintain an area-level EMT model network for model validation and verification. The technical rationale document indicates that an area-level EMT model network is not an intended requirement, and it will be better if the Standard document made this intention more obvious.

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

R6 should be removed from the standard altogether or reworded such that TPs can identify and then request an EMT model for facilities that are a risk.

Reasons for exclusion:

1. EMT modeling for every BES facility will create an undue burden and expense for GOs, TOs and TPs.
2. EMT modeling software requires specialized computer hardware for analysis and is expensive.
3. EMT software analysis requires a unique set of engineering skills and requires much training.
4. There is no evidence from TPs that every facility has a need for an EMT model.
5. Not all facilities have recording equipment installed and configured to capture large signal disturbance events and the facility response. This means more equipment and manpower costs to purchase, install and maintain.
6. There is no way to stage a large signal disturbance system test. If one could be derived, it would likely be considered a BES reliability risk by the TP and RC and not allowed.

If not removed altogether, we do not agree with the Requirement 6.1. as it relates to attestations from the original equipment manufacturer (OEM). First, it is the registered entities responsibility to ensure that model represents that actual equipment's configuration. An attestation from the OEM adds no reliability value as the OEM does not have the same motivations as a registered entity. The reliability value arises from a model that accurately represents the control configuration of the equipment. Second, the requirement is indirectly applying a NERC Standard requirement to

organizations that are not identified as entities that are required to be registered with NERC pursuant to the NERC Rules of Procedure. Third, do Transmission Planners need or want an attestation that the model matches the equipment's configuration? It seems that the intention of the requirement is to ensure that model matches the actual equipment configuration. If this is in fact the case, then the requirement should be simply written as follows: "A responsible entity shall ensure that the model accurately represents the actual control configuration of the equipment." or something to that effect. Then in the technical rational the SDT could provide examples of how an entity could demonstrate compliance with the requirement, including OEM attestations, comparison reports, et cetera. Writing the requirement in this manner would not limit the possibilities of how a responsible entity can verify that the model matches the actual equipment configuration.

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE requests clarification on intent of DT's meaning of verification and attestation toward R6. Attestations are unenforceable on OEMs because they are non-registered entities. A better solution would be to include model requirement in OEM contracts moving forward.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Manitoba Hydro recommends that this requirement should be limited only to newly interconnecting inverter-based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, LCC HVDC identified in Section 4.2.5.1, and VSC HVDC identified in 4.2.5.2 to the BPS and to upon request of any of these applicable in-service devices by the TP/PC. EMT models are complex, and it will take a long time to train personnel and develop EMT models. Developing the EMT models for all the applicable in-service devices could be very challenging due to a lack of resources and lack of equipment manufacturer(s) support. This significant compliance cost issue of developing EMT models of these applicable in-service devices could be managed by leaving it to upon request of any of these applicable in-service devices by the TP/PC (based on their experience and study's needs).	

R6 and R6.4 call out LCC and VSC HVdc separately. Suggest calling out 4.2.5 as this is more generic. Some grid codes in Europe are starting to demand that all HVDC regardless of technology behave the same way as a VSC can or a normal generator does. This is possible with FACTS or synchronous condensers added to LCC

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 provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Recommend that the January 1, 2023 commission date exemption should be removed, as this date will eliminate all IBRs currently in-service.

In addition, since the standard is not being proposed as retroactive and has up to a 10-year implementation period, it is unclear why R6, Part 6.2 essentially makes device tests optional. Rather than merely requiring documentation of the reason that device tests are unavailable, Part 6.2 should establish objective, auditable criteria (or some other oversight process) for when it is acceptable for a device test to be unavailable.

Likes 0	
Dislikes 0	

Response

David Kwan - Ontario Power Generation Inc. - 4 - NPCC

Answer	Yes

Document Name	
Comment	
Concur with NPCC RSC comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to Requirement R6, however, the industry is still in many cases developing the needed skills surrounding EMT model verification. For this reason, we ask that the SDT consider adding non-substantive language to Requirement R6 that might clarify that asset owners are not solely responsible for verifying the integrity of EMT models supplied by OEMs, but instead should work cooperatively with their Transmission Planners in that verification.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
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 agrees with the proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
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	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
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	
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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name 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	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
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

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
Answer	
Document Name	
Comment	
Abstain. R6 is only for inverter based resources.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the language proposed in MOD-026-2 Requirements R7, R8, and R9? 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	
Please add the text “a technical justification such as simulated unit or plant response not matching measured unit or plant response” to R9 so as to maintain continuity with MOD-026-1 R5. It should then state… “Each Generator Owner or Transmission Owner shall provide a written response to its Transmission Planner after receiving a notification of denial under Requirement R8 or a request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies or a technical justification such as simulated unit or plant response not matching measured unit or plant response, within the timeframe in MOD-026-2 Attachment 1.”	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC Generator Working Group: Request clarity on if you replace a piece of equipment with an in-kind with the same settings whether you have to send an updated model.	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

For R7, Entergy recommends following: In place of “alters dynamic response” characteristics, The standard should reference to the qualified changes referenced by FAC- 002.

The NERC Technical Rationale document for R7 states that “If changes to dynamic performance result from these equipment or facility modifications, the dynamic models used to assess their impact to the grid need to be revalidated and resubmitted so Transmission Planners may study the reliability impact of the new as-built facility on the grid”. Here the term dynamic response is used. Entergy recommend R7 should be re-written to align with the Technical Rationale document and include more information to define the term “alters the dynamic response”.

Entergy agrees with R8 & R9.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The term, “control mode,” in R7 should be changed to, “type of control,” as was done in R3.1. Combined cycle units frequently shift between the load setpoint control mode and firing temperature limit control mode, for example, and fossil units at very high output go from throttling to the valves-wide-open mode. These transitions alter the response to frequency disturbances, but it would be impossible to reverify models for each episode. MOD-026-2 R7 should apply only when converting a fossil unit from mechanical hydraulic to electro-hydraulic governors or making a similar change in control type.

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3

Answer	No
Document Name	

Comment

For R7, Entergy recommends following: In place of “alters dynamic response” characteristics, The standard should reference to the qualified changes referenced by FAC- 002.

The NERC Technical Rationale document for R7 states that “If changes to dynamic performance result from these equipment or facility modifications, the dynamic models used to assess their impact to the grid need to be revalidated and resubmitted so Transmission Planners may study the reliability

impact of the new as-built facility on the grid". Here the term dynamic response is used. Entergy recommend R7 should be re-written to align with the Technical Rationale document and include more information to define the term "alters the dynamic response".

Entergy agrees with R8 & R9.

Likes 0	
Dislikes 0	

Response

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

It will be more effective if both Transmission Planners and Planning Authorities have model review responsibility, as opposed to Transmission Planners alone. This is a better model review process for Transmission Owners' dynamic reactive facilities where they are also Transmission Planners. This sentiment was expressed in our previous comments.

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	No
Document Name	

Comment

At requirement R7, note 15, section (a) should refer to "hardware alteration" instead of "software alteration", because software change is already covered under section (e). There should also be a note about the replacement of a failed component with an identical part, whether it is considered a change or not.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment	
R8 states that models should meet acceptance criteria established in R1, but does not mention the modeling requirements established in R2-5. This creates the implication that models do not need to meet modeling requirements outlined in R2-5. Our comments for R2/R3 and R4/R5 would rectify this discrepancy.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE requests clarification on the definition of software/hardware and which pieces of software/firmware are covered in the referenced requirements. As written, NEE thinks the language is too generic, can extend to a large population of software/firmware, and can trigger multiple submissions and reviews, with no changes.	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	No
Document Name	
Comment	
R8 states that models should meet acceptance criteria established in R1, but does not mention the modeling requirements established in R2-5. This creates the implication that models do not need to meet modeling requirements outlined in R2-5. Our comments for R2/R3 and R4/R5 would rectify this discrepancy.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No

Document Name	
Comment	

As a Generator Owner and Transmission Owner we will continue to provide requested model data, but at this time there are no NERC approved EMT models with limited software/expertise.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE does not support Requirement 8 as stated. CEHE recommends the Planning Coordinator (PC), in coordination with the Transmission Planner (TP) should review EMT models as commented in question 4 regarding Requirement 6 (R6). Therefore, R6 should be excluded in the review referenced in R8. It will be more costly for TP to take on this responsibility since there is a need for more experience and training in EMT modeling. CEHE recommends the following revisions to MOD-026-2, R8,

"Each Transmission Planner shall review the model(s) and accompanying information submitted under Requirements R2-R5 or R7 & R9 and provide written responses to the submitter…."

CEHE suggests clarification on the terminology "review", "verify" and "validate" as these are used interchangeably. It is important for these terms to be clearly understood throughout the standard and used as intended.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - 1 - SERC

Answer	No
Document Name	

Comment

R8 is a purely administrative requirement for the TP. The requirement should be focused on any technical comments from the TP or PC being responded to by the GO or TO. This appears the be the intent of R9. Therefore, R8 should be removed.

It is important to note that adding purely administrative requirements to standards is contrary to recent and past NERC Standards Efficiency efforts and places an undue burden on an entity to maintain compliance evidence for a task that is either unnecessary or does not benefit reliability.

Regarding R9:

The GO or TO providing “technical justification and supporting evidence for maintaining the current model” may be an unacceptable response to deficiencies identified the TP or PC. This would imply the right of the GO or TO to by-pass TP or PC requirements and diminish the ability of the TP and PC to perform needed studies with a potentially deficient model. It recommended to either strike this portion of the requirement, or provide a mechanism for dispute resolution.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	No
Document Name	

Comment

At requirement R7, note 15, section (a) should refer to “hardware alteration” instead of “software alteration”, because software change is already covered under section (e). There should also be a note about the replacement of a failed component with an identical part, whether it is considered as a change or not.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

At requirement R7, note 15, section (a) should refer to “hardware alteration” instead of “software alteration”, because software change is already covered under section (e). There should also be a note about the replacement of a failed component with an identical part, whether it is considered as a change or not.

Likes 0	
Dislikes 0	

Response

David Kwan - Ontario Power Generation Inc. - 4 - NPCC

Answer	No
Document Name	
Comment	
Concur with NPCC RSC comments.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
Protection and limiter setting changes are not appropriate to model per the above comments	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Protection and limiter setting changes are not appropriate to model per the above comments	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	

Comment	
The requirement to perform the verification within 120 days could be challenging based on: 1. The criteria identified between the PC and TP for the reviews. 2. The number of Generators submitting their data near the two year implementation time frame. With only a few in the industry with expertise in EMT studies, this could place TPs at a significant disadvantage with staff not trained to complete EMT model validation.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	No
Document Name	
Comment	
The IRC SRC believes the objective of the SAR, to provide planners with data and verification of generator VAR output capability, is imperative in today's changing resource mix. System operators are depending more on VAR support from rotating machine generation while there are fewer of these facilities available relative to the overall generation fleet. Therefore, our comments and recommendations here are critical to ensure planners and operators have a more accurate measure of generator capability. **Revise Requirement 7 to require the provision of verified models in a timelier manner** Under the draft Requirement R7, the Generator Owner (GO) and Transmission Owner (TO) must provide the TP an updated verified model or a Plan to verify the model after making a change that alters their equipment's dynamic response characteristics. For the reasons discussed below, the SRC believes that the GO or TO should be required to provide a verified model within 30 or 60 days of implementing the change and should not be given the option to provide a plan to verify the model in lieu of providing the verified model. If the drafting team elects to maintain the option to provide a plan, the	

SRC notes that Attachment 1, Row 5 and the VSL penalties for R7 do not distinguish a periodicity difference between providing an updated verified model or a Plan to provide the model. If the option to provide a plan is retained in the standard, the SRC requests a shorter timeframe be allowed for a GO/TO to provide a Plan if they do not intend to or cannot provide the actual verified model within the allowed timeframe. The SRC suggests 30-60 days is an adequate timeframe within which to provide an updated verified model (or a plan to verify the model, if that option is retained). In fact, there are multiple documents that support the need for more aggressive timelines to provide the verified models necessary to adequately model system, as cited below:

In its Odessa disturbance report, NERC stated that it "strongly recommends that all TPs and PCs ensure that all qualified changes encompass any changes to equipment that can alter the electrical output of the facility. These changes should be *studied by the TP and PC prior to implementation* in the field by the GO or developer; this ensures that all potential adverse BPS reliability impacts are identified via simulations rather than identified in real-time operation" (emphasis added). Therefore, an updated model should be provided before the change is implemented.

Likewise, the SAR for this project indicates there is an Industry Need: "Accurate model response is required for the engineers to adequately study system conditions. Hence, it is crucial that all parameters in a model be verified in some way."

Additionally, the SDT's response to previous comments suggested that FAC-002 would be a better venue to address modeling needs. In that case, the allowed time to submit a verified model (180 days + 365 days per Attachment 1, rows 5 and 6) is excessive. If the model update is already being provided prior to the implementation of the change for FAC-002 evaluation, the SRC requests the SDT modify the requirement to require a TO/GO provide the updated verified model within an additional 30 or 60 days after implementing the change, as the model verification should be performed when the change is implemented, which means that 30 or 60 days after implementation of the change is a reasonable timeframe within which to provide the verified model and there is no need for the option to provide a plan to verify the model instead of providing the actual updated verified model.

Furthermore, proposed requirement R9 only applies to models that are not acceptable during the initial submittal and review. It does not address data verification or model validation concerns that arise after an initial acceptance. As such, the SRC has concerns with removal of the existing technical concerns requirement found in MOD-026/-027. The SRC disagrees with the SDT that R9 is sufficient to cover the scenarios presented below and asks that the SDT add a direct requirement for these situations.

For example, PJM uses the MOD-026/27 technical concerns requirement to initiate modeling updates from generators under the following scenarios:

A TP/PC receives MOD-026/27 models from a generator. Following this approval and via a subsequent MOD-032 submittal (annual model submittal) a different model is received than the previously accepted model(s). The SRC does not agree with the Standard Drafting Team (SDT)'s position that a GO's noncompliance would address this concern as it leaves the TP/PC with uncertainty as to which model to use in their studies.

A PC/TP identifies a concern with a GO's model response under MOD-033. Under the current practice, a PC/TP could request resolution with the dynamic response concerns under the appropriate MOD-026 or MOD-027 standard technical requirements. The SRC believes removing the technical concerns breaks the link between MOD-033 dynamic concerns and getting those concerns resolved under the new MOD-26-2 standard.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	

Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
R8 stated that the submitted model(s)should meet the acceptance criteria established in Requirement R1. Is that mean that the submitted model(s) does not need to meet the minimum requirements stated R2-R6 as long it is meet the acceptance criteria established in Requirement R1 by TP/PC? Some clarification may be needed. Manitoba Hydro agrees that the submitted model(s) shall meet the acceptance criteria established in Requirement R1 by TP/PC (i.e. some of the limiters and protection function has only to be modeled if it was stated in the R1)	
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	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
No Comments.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
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 agrees with the proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with proposed language. Kimberly Turco on behalf of Constellation Segments 5 and 6	
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 proposed language. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
Ameren agrees with and supports NAGF comments.	
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 language proposed for MOD-026-2 R7, R8, and R9.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
No Comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the proposed changes made to Requirements R7, R8 and R9.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters	
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	
John Pearson - ISO New England, Inc. - 2	
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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
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	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
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	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 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	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the language proposed in MOD-026-2 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Lovita Griffin - Austin Energy - 3	
Answer	No
Document Name	
Comment	
Austin Energy disagrees with this posting of MOD-026 due to lack of formal definition for the term Inverter Based Resource (IBR), and believes that this term should be defined within the NERC Glossary rather than in individual Standard language to ensure consistency across Standards.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
:For the initial reviews for new generating plants, the GO has a year in which to submit their MOD-026 data to the TP. The TP however only has 120 days to verify the models regardless of how many new plants are being connected within their area in addition to the existing plants that may also be submitting MOD-026 data for review. With the massive shift in generation resources to IBR, this could leave TP very short staffed to complete the required reviews within the time allotted and complete the EMT model reviews. A longer time frame for new plant reviews would be appropriate during this time of new build-out.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
David Kwan - Ontario Power Generation Inc. - 4 - NPCC	
Answer	No
Document Name	
Comment	
Concur with NPCC RSC comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP strongly feels Inverter Based Resources should have separate standards.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	
1. Equivalent Unit Verification Condition At row 9 of attachment 1 of MOD-026-2, clarification is needed to indicate when this row applies, because in case of misinterpretation, the impact would be major in terms of model verification work for the GO. Does it apply to rows 1, 2, 3, 4, 10, 11, 12 and 13? The following text from the “Required Action” column of row 9: “Verify the model(s) of a different equivalent unit during each 10-year verification period.” suggests that row 9 only applies to row 3. Please add text in row 9 to indicate to which row(s) row 9 applies.	

2. Unit vs Facility
At row 10 of attachment 1 of MOD-026-2, in the “Verification Condition” column, term “unit or Facility” is used. This differs from all other sections where “Unit” has been replaced by “Facility”, to be consistent with definition of “Facility” at section 4.2. Please harmonize.

Also, at row 9 of attachment 1 of MOD-026-2, term “generating unit or synchronous condenser” is used; should the term “Facility” be used instead? If “generating unit or synchronous condenser” text is kept, in the “Verification Condition” column, this row should only apply to R2 and R3 (as R4, R5 an R6 are excluded from “generating unit or synchronous condenser” term).

3. Change in the “BES definition” applicability criteria
Add a new row in attachment 1 to cover for a “BES definition applicability criteria change”, with an implementation timeframe of approximately 3 years. Rationale: If a new version of the “BES definition” with new applicability criteria is released in the future, an implementation period will be necessary to allow the implementation of the newly applicable units. This is not covered in the proposed MOD-026-2. If MOD-026-2 is kept as proposed, a change in the applicability criteria of the “BES definition” will cause the newly applicable units to be instantly compliant, which is impossible.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	No
Document Name	

Comment

1. Equivalent Unit Verification Condition

At row 9 of attachment 1 of MOD-026-2, clarification is needed to indicate when this row applies, because in case of misinterpretation, the impact would be major in terms of model verification work for the GO. Does it apply to rows 1, 2, 3, 4, 10, 11, 12 and 13? The following text from the “Required Action” column of row 9: “Verify the model(s) of a different equivalent unit during each 10-year verification period.” suggests that row 9 only applies to row 3. Please add text in row 9 to indicate to which row(s) row 9 applies.

2. Unit vs Facility

At row 10 of attachment 1 of MOD-026-2, in the “Verification Condition” column, term “unit or Facility” is used. This differs from all other sections where “Unit” has been replaced by “Facility”, to be consistent with definition of “Facility” at section 4.2. Please harmonize.

Also, at row 9 of attachment 1 of MOD-026-2, term “generating unit or synchronous condenser” is used; should the term “Facility” be used instead? If “generating unit or synchronous condenser” text is kept, in the “Verification Condition” column, this row should only apply to R2 and R3 (as R4, R5 an R6 are excluded from “generating unit or synchronous condenser” term).

3. Change in the “BES definition” applicability criteria

Add a new row in attachment 1 to cover for a “BES definition applicability criteria change”, with an implementation timeframe of approximately 3 years.

Rationale: If a new version of the “BES definition” with new applicability criteria is released in the future, an implementation period will be necessary to allow the implementation of the newly applicable units. This is not covered in the proposed MOD-026-2. If MOD-026-2 is kept as proposed, a change in the applicability criteria of the “BES definition” will cause the newly applicable units to be instantly compliant, which is impossible.

Likes 0	

Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
Refer to the response to question 5 regarding R8. Row 7 is purely administrative and should be removed.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
LADWP recommends revising the second paragraph of the required action for Row 12 to read as follows: *"If the current average net capacity factor over the most recent three calendar years exceeds 5%, then perform model verification in accordance with one of the following:* 1. *the required action of row 1;* 2. *the required action of row 3; or* 3. *within 365 calendar days."* As currently written in Draft 3, this language could be interpreted to require asset owners to perform model validation within 365 calendar days even if 10 calendar years have not passed since the previous transmittal. For instance, an asset owner that transmitted modeling data to the Transmission Planner in year 0 may find in year 1 that the average net capacity factor is less than 5%. If the asset owner then finds in year 2 that the net capacity factor has increased to more than 5%, Draft 3 would require the asset owner to complete model verification within 365 calendar days regardless of the fact that model validation was completed on the same equipment not long ago.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not support all Attachment 1 as written; more clarification is needed on item 13 Requirement 6 exemption required action.	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
SIGE supports CEHE's comments.	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation does not agree with the requirement to respond within 120 days which has been reduced from 180 days. As most technical justifications require vendor analysis 180 days is required. Alison Mackellar on behalf of Constellation Segments 5 and 6	
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	No
Document Name	
Comment	

1. Equivalent Unit Verification Condition

At row 9 of attachment 1 of MOD-026-2, clarification is needed to indicate when this row applies, because, in case of misinterpretation, the impact would be major in terms of model verification work for the GO. Does it apply to rows 1, 2, 3, 4, 10, 11, 12, and 13? The following text from the "Required Action" column of row 9: "Verify the model(s) of a different equivalent unit during each 10-year verification period." suggests that row 9 only applies to row 3. Please add text in row 9 to indicate to which row(s) row 9 applies.

2. Unit vs Facility

In row 10 of attachment 1 of MOD-026-2, in the "Verification Condition" column, the term "unit or Facility" is used. This differs from all other sections where "Unit" has been replaced by "Facility", to be consistent with the definition of "Facility" in section 4.2. Please harmonize.

Also, in row 9 of attachment 1 of MOD-026-2, the term "generating unit or synchronous condenser" is used; should the term "Facility" be used instead? If the "generating unit or synchronous condenser" text is kept, in the "Verification Condition" column, this row should only apply to R2 and R3 (as R4, R5, and R6 are excluded from the "generating unit or synchronous condenser" term).

3. Change in the "BES definition" applicability criteria

Add a new row in attachment 1 to cover for a "BES definition applicability criteria change", with an implementation timeframe of approximately 3 years.

Rationale: If a new version of the "BES definition" with new applicability criteria is released in the future, an implementation period will be necessary to allow the implementation of the newly applicable units. This is not covered in the proposed MOD-026-2. If MOD-026-2 is kept as proposed, a change in the applicability criteria of the "BES definition" will cause the newly applicable units to be instantly compliant, which is impossible.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Constellation does not agree with the requirement to respond within 120 days which has been reduced from 180 days. As most technical justifications require vendor analysis 180 days is required.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

For post-commissioning model verifications (every 10 years), if facility owners can demonstrate that all facility control functions and settings are consistent with the original functions and settings, no model verification should be required.

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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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 recommends copying the following note from Row Number 5 to Row Number 3. This note is helpful in interpreting Row Number 3 in Attachment 1.

“In order for the transmittal to reset the 10-year anniversary transmittal date for Requirement R2-R6 as described in Row 3, all model(s) and model parameters must be verified according to the applicable requirement(s) and included in the transmittal.”

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3	
Answer	No
Document Name	
Comment	
Entergy disagree with 10-year repeat for this standard. R7 addresses changes that would affect the model. Repeating every 10 years when no changes have been made provides no benefit to the BES. Initial verification date should follow the current MOD-026 or MOD-027 verification dates per unit. For Row number 5 of attachment 1: Entergy Recommend language to be changed to “within 180 calendar days after commissioning and placing into service the in- service equipment after making a change to in- service equipment.”	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Units that normally can respond only to over-frequency events should be deemed compliant upon submitting an attestation of unresponsiveness, as they are now, rather than having to conduct tests as per Row 11. Our experience is that the rest windup period of combined cycle STG HPT control valve controllers that have saturated at maximum output is usually so long that overspeed excursions are over before the unit can react. We may therefore spend significant time and money on step-change-and-hold testing to construct models that do not represent what actually happens under the rapidly changing circumstances of actual disturbances. It seems moreover that TPs don’t actually care much about load-reduction capability, and testing should not be mandated unless there is a BES reliability justification.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

In general, Attachment 1 is overly complex. It is recommended to simplify and reorganize. Perhaps consider including the periodicity information within the requirements and remove attachment 1.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Entergy disagree with 10-year repeat for this standard. R7 addresses changes that would affect the model. Repeating every 10 years when no changes have been made provides no benefit to the BES. Initial verification date should follow the current MOD-026 or MOD-027 verification dates per unit. For Row number 5 of attachment 1: Entergy Recommend language to be changed to “within 180 calendar days after commissioning and placing into service the in- service equipment after making a change to in- service equipment.”	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	No
Document Name	
Comment	
The MOD-026-2 Attachment 1 continues to use inconsistent possessive form of Transmission Planner and the representative pronoun. All usage of “the Transmission Planner” should be modified to “the its Transmission Planner.”	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
No Comments.	
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 language proposed for MOD-026-2 Attachment 1.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
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 agrees with the proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
No Comments.	

Likes 1	Lincoln Electric System, 5, Millard Brittany
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	Yes
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	

Comment

AECI supports comments provided by the NAGF.

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

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
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

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

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	
Sheila Suurmeier - Black Hills Corporation - 5	
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	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO

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

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

George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
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	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
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	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment	
EEI supports the changes to MOD-026-2, Attachment 1.	
Likes 0	
Dislikes 0	
Response	

7. The standard drafting team (SDT) believes the language of MOD-026-2 addresses the issues outlined in the 2 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.

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	No
Document Name	
Comment	
It is difficult to assess the “cost effectiveness” of the proposed revisions of MOD-026-2, but there is no doubt that Transmission Planner costs will increase.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not agree the language of MOD-026-2 addresses the issues outlined in the two SARs in a cost effective manner. The proposed revisions would result in the Generator Owner of synchronous units incurring additional, significant costs to model protection functions at no added benefit to the reliability of the BES.	
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 provided by the MRO NSRF.	
Likes 0	

Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Entergy believes Repeating model validation just to “repeat model validation” is not cost effective. For this to be truly cost effective, Entergy recommend this should be limited to performing model validation ONLY when changes are made that alter the equipment’s response. Entergy does not agree with current language of R2 and R3, which requires data that may or may not be required by Transmission Planning, as being cost effective.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Development of EMT models requires trained individuals and time. Therefore, SDT should consider the comments provided in Q4. Adding more prescriptive to minimum modeling requirements may not translate to more accuracy in the modeling. It significantly increases compliance costs with a minimum improvement in reliability as it may not address an actual modeling gap /concerns from the TP/PC perspective. Most likely it will put a lot of burden on the generator and transmission owners in preparing this documentation and models at the same time the burden of planners reviewing this documentation and models that may not address their concerns and some of these prescriptive models may not be used or needed by planners for their study purposes.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

See our comments above.

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3

Answer	No
Document Name	

Comment

Entergy believes Repeating model validation just to “repeat model validation” is not cost effective. For this to be truly cost effective, Entergy recommend this should be limited to performing model validation ONLY when changes are made that alter the equipment’s response.

Entergy does not agree with current language of R2 and R3, which requires data that may or may not be required by Transmission Planning, as being cost effective

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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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 agrees that the proposed changes address the issues outlined in the two SARs in a cost effective manner. However, in light of the upcoming changes from the NERC IBR Work Plan, Tacoma Power does not agree that approving the current MOD-026-2 without these upcoming changes is cost effective. Once the NERC IBR Work Plan actions are identified in the next six months, another revision to the MOD-026-2 Applicability Section will be required. Posting multiple revisions to the same Standard in a short time period (less than year) is not an effective use of entities’ time. Tacoma Power recommends delaying the completion of Project 2020-06 until the scope of the NERC IBR work plan can be included, so only one version needs to be implemented.

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	

With respect to R6 and EMT models: A computer outfitted to run EMT modeling software is expensive due to processing power needs. EMT software is very expensive. Training engineers in house or consulting out to do the modeling is expensive. Installing equipment at BES facilities to capture large signal disturbance events is expensive.

Recommend TPs analyze facilities that pose the greatest risk and let them decide if an EMT model is needed.

Likes 0	
Dislikes 0	
Response	

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	No
Document Name	
Comment	

Oncor agrees that reviewing EMT models along with positive sequence dynamic models will enhance model accuracy. However, it will be very difficult and potentially resource intensive to build and maintain an area-level EMT model network for model validation and verification. The technical rationale document indicates that an area-level EMT model network is not an intended requirement, and it will be better if the Standard document made this intention more obvious.

Likes 0	
Dislikes 0	
Response	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF does not agree that Requirement 6.1. is cost effective, as it creates a monopoly. With respect to R6 and EMT models: A computer outfitted to run EMT modeling software is expensive due to processing power needs. EMT software is very expensive. Training engineers in house or

consulting out to do the modeling is expensive. Installing equipment at BES facilities to capture large signal disturbance events is expensive. The MRO NSRF recommends TPs analyze facilities that pose the greatest risk and let them decide if an EMT model is needed.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports the comments submitted by Tacoma Power pertaining to cost-effectiveness.	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by the American Public Power Association (APPA). In addition to those comments, we believe that the SDT has overlooked the costs related to the purchase of the EMT software, hardware to run the software, and personnel training that will be required to use these relatively new models and studies. NERC has already received more than 700 registration requests for its upcoming EMT Boot Camps which highlights industry's demand for this type of training. More EMT training will certainly be needed for engineers to become proficient in implementing the proposed revisions to MOD-026. Transmission Planners should be the ones who determine which facilities pose the highest risk to the Bulk Power System and decide if an EMT model is required.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	

Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments: We believe that Requirement R6.1 is not only prohibitively costly but also has very little reduction in risk to the reliability of the grid.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation relies on third party contractors for the completion of MOD-026-1 and MOD-027-1 models due to this lack of expertise and modeling software. The addition of expanded modeling requirements will increase the scope and likely the cost of analysis being completed, as there is limited experts in the industry. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
As outlined above in AZPS's responses to Question 1, AZPS does not agree that the SDT's recommendations are cost effect because many of the issues are already being addressed by other standards or will require significant additional work with minimal benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation relies on third party contractors for the completion of MOD-026-1 and MOD-027-1 models due to this lack of expertise and modeling software. The addition of expanded modeling requirements will increase the scope and likely the cost of analysis being completed, as there is limited experts in the industry. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	

Dislikes 0	
Response	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
Answer	No
Document Name	
Comment	
Combining MOD-026-1 and MOD-027-1 into a single Standard will result in significant administrative costs and time for entities with a well-established compliance program for these standards. Many work hours from engineers or consultants, and other staff will be required to modify all of the compliance processes already established.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
The changes to MOD-026-2 to require GO/TOs to have validated models to provide to the TP is not consistent with the proposed SARs. The EMT modeling requirements is not mentioned in either SAR and implementation would not be cost effective.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE has not performed a cost evaluation and the cost factor is unknown. EMT modeling requirements need to be expanded and clarified.	
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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy does not agree that Requirement 6.1. is cost effective, as it creates a monopoly. With respect to R6 and EMT models: A computer outfitted to run EMT modeling software is expensive due to processing power needs. EMT software is very expensive. Training engineers in house or consulting out to do the modeling is expensive. Installing equipment at BES facilities to capture large signal disturbance events is expensive. NV Energy recommends TPs analyze facilities that pose the greatest risk and let them decide if an EMT model is needed.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
LADWP requests that the SDT revisit the language in Row 12 of Attachment 1. As currently written in Draft 3, this language could be interpreted in a way that requires some asset owners to perform model validation at a frequency that is not cost effective. See LADWP’s comment for question 6.	
Likes 0	

Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
Cost impact is not clear. The provisions for the GO/TO to provide models and model data is a positive addition, however, as stated in the responses to the other questions, there are issues regarding the inclusion of the PC in R1 and the subsequent exclusion of the PC in the other requirements and the proposal for a purely administrative requirement in R8.	
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 supoprts and incorporates by reference the comments of the MRO NSRF for question #7.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

NRG reiterates that GOs are not part of the transmission planning process and should not function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments. GOs therefore should not shoulder the burden of costs for these validation checks.

Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NERC Standards generally do not have a cost analysis performed as part of them. NRG reiterates that GOs are not part of the transmission planning process and should not function in a transmission planning role to perform model parameterization checks, usability, initialization, and interoperability assessments. GOs therefore should not shoulder the burden of costs for these validation checks.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
The way that R1 has been written could make the standard significantly more complicated to comply with. A possible method to decrease concern is to remove the PC from R1	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	

Comment	
We believe that Requirement R6.1 is not only prohibitively costly but also has very little reduction in risk to the reliability of the grid.	
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	
We believe that Requirement R6.1 is not only prohibitively costly but also has very little reduction in risk to the reliability of the grid.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

While FirstEnergy does feel confident in obtaining this in a cost-effective manner, more guidance from our Transmission Planner and NERC would ensure a more efficient way of achieving consistency and compliance.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
The IRC SRC agrees that applicable entities may incur costs to comply with MOD-026, however, the cost is warranted as the need for verified dynamic models and data for BES-connected Facilities is very important for accurate TP and PC modeling purposes and ultimately the reliable operation of the BES.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
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	
John Pearson - ISO New England, Inc. - 2	
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	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Kwan - Ontario Power Generation Inc. - 4 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	
Document Name	
Comment	
Abstain from commenting	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC will defere to the applicable entities to comment on cost effectiveness.	
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	
At this time PG&E does not have sufficient information to determine if the modifications are cost effective.	
Likes 0	

Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy agrees with the proposed language and thanks the drafting team for their work.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Desmarie Waterhouse - American Clean Power Association - 4 - NA - Not Applicable	
Answer	
Document Name	
Comment	
On their face, the proposed MOD-026-2 changes address the issues outlined in the two SARs in a cost effective manner. However, impending changes from the NERC Inverter-Based Resources (IBR) Work Plan must be considered. Once the NERC IBR Work Plan actions are identified in the next six months, another revision to the MOD-026-2 Applicability Section will be required. This would be inefficient and not cost effective. Posting multiple revisions to the same standard in a short time period (less than year) is not an efficient or effective use of ERO entities' time. Therefore, we recommend delaying the completion of Project 2020-06 until the scope of the NERC IBR work plan can be included, so only one version needs to be implemented.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

8. The SDT proposes a 2-year implementation plan for MOD-026-2 Requirements R1, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 and R7 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained for Requirements R2-R5 from the date of previous model verification. Do you agree with the proposed implementation plan timeframes? If you think an alternate timeframe is needed, please propose an alternate implementation plan with detailed explanation.

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

Answer	No
Document Name	

Comment

The implementation timeframe is a concern due to potential issues due to R1 (see comments above). If a large number of generating units submit their information at a similar point in time (i.e. near the requirement's implementation due date), TP's could have problems meeting the 120 day due date as they begin ramping up this work and engage a contractor to perform the EMT verifications. Most TPs will not have the required skill set at the beginning of implementation of this standard to complete an EMT model review.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

SRP strongly feels Inverter Based Resources should have separate standards.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation agrees with the intent of the drafting team is that the original 10 year periodicity, however it could be interpreted differently by regions that a new model is required that meets requirements R2-R6 once implemented. The 10 year periodicity for existing models should be clearly defined in the implementation plan so it is not left to interpretation.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

As written, R1 applies to both synchronous and inverter based resources. Currently there are no EMT models available for synchronous generation as it has not been determined to be useful. For these reasons, EMT models should not be required for synchronous resources, and only required for inverter based resources on an as needed basis such as if the model response does not match the actual response from a system event.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation agrees with the intent of the drafting team is that the original 10 year periodicity, however it could be interpreted differently by regions that a new model is required that meets requirements R2-R6 once implemented. The 10 year periodicity for existing models should be clearly defined in the implementation plan so it is not left to interpretation.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Is there evidence that there will be a trained workforce that can meet the EMT study throughput needs in the next 5 years? BPA finds it unlikely that 5 years is enough lead time, given where the industry currently stands regarding lack of expertise. For BPA, the lead time required to acquire the software, hire staff and allow several years for training, is significant. Additionally, the Asset Owners (GO and TO) will also need to come up to speed before they could even submit a useable model to their Transmission Planner. Similar to the CAP development and implementation phasing outlined in the TPL-001-5 Implementation Plan, BPA recommends there be a longer implementation timeframe (longer than 24 months) for R1 and R8 to allow Transmission Planners and Planning Coordinators to adopt practices and train Subject-Matter Experts related to understanding EMT models, developing processes for review of EMT models that will enable successful EMT simulations. Then, an additional longer implementation timeframe (longer than 36 months) for EMT Asset Owners to gain the expertise required to create and validate high-quality EMT models per R6.	
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	
The R6 modeling effort needs longer to implement for several reasons. The version -1 original 10 year phase in should apply to this additional modeling effort. Equipment must be bought and installed. EMT software must be purchased, and engineers must be trained on how to use it. Large signal disturbances must occur, but until equipment is installed and operational, data cannot be captured.	
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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	

See comment above regarding coordination of Project 2020-06 with the upcoming NERC IBR work plan actions.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Any changes to MOD-026-1 and MOD-027-1 should have the a ten-year implementation cycle, to be in step with the decade-long periodicity of these standards.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Development of EMT models for existing Facilities as required by R6 (new requirements) may be difficult to achieve with the proposed implementation plan. May R6 may require a separate implementation plan for the existing Facilities.

Likes 0	
Dislikes 0	

Response

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 1, 3; Raj Hundal, Powerex Corporation, 6; - Patricia Robertson, Group Name BC Hydro Balloters

Answer	No
Document Name	

Comment

BC Hydro recommends that the SDT work with the software vendors and technical community (e.g., WECC MVS) to obtain their endorsement on the current implementation timelines for R2-R5 (i.e., maintaining the existing facilities' 10-year reoccurring periodicity and allowing a 3-year timeline for newly applicable facilities), ensuring sufficient lead time is allocated for developing suitable models for Out-of-Step Relays (OOSR) for generators. So far, BC Hydro has been unable to find a protection model that can be used to correctly model those types of OOSR used in its system.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
No Comments.	
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 implementation plan.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy agrees with the Implementation Plan and thanks the drafting team for their work.	
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 agrees with the proposed modifications	

Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
No Comments.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objection to the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
none	
Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
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	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Kwan - Ontario Power Generation Inc. - 4 - NPCC	
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	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
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	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
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	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
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	

George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
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	
James Keele - Entergy - 3	
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	
John Pearson - ISO New England, Inc. - 2	
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	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC will defere to the applicable entities to comment on the implementation plan	
Likes 0	
Dislikes 0	
Response	

9. Provide any additional comments for the SDT to consider, if desired.

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	
Document Name	
Comment	
The MOD-026-2 Requirement R1, Part 1.6 and the Technical Rationale page 2, paragraph 3 references to "database" **remain** functionally incorrect. This language perpetuates the poorly used term "database" from MOD-026-1 and MOD-027-1 Requirement R1 (bullet 3) which is problematic if interpreted that Transmission Planners are obligated to maintain a database of Generator Owner or Transmission Owner models. This is inconsistent with MOD-032-1 for jointly developed modeling data requirements and reporting procedures of the Transmission Planner and Planning Coordinator, as well as the requirement for Generator Owner or Transmission Owner to submit modeling data to its Transmission Planner and Planning Coordinator. Transmission Planners are not required to maintain a database of models from which Generator Owners and Transmission Owners obtain. On the contrary, the closest requirement to one that requires models to be made available is given in MOD-032-1 Requirement R4 which obligates each Planning Coordinator to make models available to the ERO or designee. Each reference to "Transmission Planner's database" should be corrected to "modeling representation reflected in its Transmission Planner and Planning Authority current (in-use) models."	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP appreciates the efforts of the Standards Drafting Team. While we disagree with some aspects of what is proposed in the draft, AEP supports the SDT's overall goals and objectives. Please make the following changes to the mapping document to affirm that, in addition to HVDC, FACTS, and Synchronous Condensers, the following facilities would also be brought into scope in the proposed standard: * Individual generating units 20-100 MVA with POI 100 kV and greater in Eastern Interconnection. * Aggregate generating units 75-100 MVA with POI 100 kV and greater in Eastern Interconnection. * Individual generating units 20-50 MVA with POI 100 kV and greater in ERCOT.	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
For R2 & R3, Entergy recommends that Section 4.2 section should specify MVA thresholds rather than BES Definition, as changes to BES definition could me made without sufficient communication to Generator Owners (GOs) which could result in potential compliance violation. **Implementation plan :** Compliance Date for MOD-026-2 – Requirements R2, R3: It is unclear when Modelling must be performed for initial compliance on units that are now covered under section 4.2 that were not previously applicable.	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
· Section 4.2.5: Suggest adding “including, but not limited to:”. This is more consistent with the language in 4.2.4. HVdc technology advances rapidly, there could be hybrid LCC/VSC schemes, or new developments and not just VSC and LCC. · Foot notes 4, 5 and 10 are the same. It is sufficient to use only one foot note throughout the document to refer to the term “validation”. · Row-12 in Attachment 1, it is recommended to consider adding the definition for “net capacity factor” into NERC standard definition list. If this is not an option at this stage of the project, then consider extracting the GADS definition and place it as a footnote. · Row-13 in Attachment 1, there is no subsequent action followed by the statement “ If the OEM that commissioned the Facility was acquired, merged, or operating under a different name, the new company would be considered the OEM”. It is recommended to clearly state that TOs and GOs need to work with the new OEMs to perform model verification/validation requirements in R6.	
Likes 0	
Dislikes 0	
Response	

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

To ensure consistency and compliance, FirstEnergy suggests the Drafting Team offer direct guidance to the Transmission Planner or Planning Coordinator on testing expectations such as steps or templates.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3

Answer	
Document Name	

Comment

For R2 & R3, Entergy recommends that Section 4.2 section should specify MVA thresholds rather than BES Definition, as changes to BES definition could me made without sufficient communication to Generator Owners (GOs) which could result in potential compliance violation

MOD-026-2 Draft 3 Standard Version: Vote - Negative

Implementation plan Voting: Vote - Negative

Compliance Date for MOD-026-2 – Requirements R2, R3: It is unclear when Modelling must be performed for initial compliance on units that are now covered under section 4.2 that were not previously applicable.

Non-binding polls for the associated violation risk factors and violation severity levels - Vote – Negative opinion

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; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
Document Name	

Comment

IBR Formal Definition

Tacoma Power disagrees with this posting of MOD-026 because the term Inverter-based Resource (IBR) is not adequately defined. The SDT should create a formal definition and not attempt to define it in the footnotes of the Standard. Footnotes in standards should not be used to include part of the requirement to meet compliance. In addition, multiple Standard Projects are utilizing the term IBR, but each Standard Project is using a different definition or using the term IBR in a different context. By not defining IBR, there's a risk of inconsistency between the different Standards. Similar industry comments on the need to formally define IBR were submitted in response to Project 2021-01.

Applicability Section

The Applicability items 4.2.1 and 4.2.2 appear to be duplicative of the BES Inclusion I2. Inclusion I2 already specifies individual and aggregate facility criteria. Tacoma Power recommends combining R4.2.1 and R4.2.2 into one line item, as follows: “**4.2.1** Generating Plant/Facility or unit meeting the criteria set by Inclusion I2 of the BES definition.

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

No additional comments.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

No Comments.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

In general, BPA does not feel that the industry is ready for EMT Modeling and is not convinced that reliability risks will be mitigated with EMT studies. Controller and relay settings drive exposure to the risks identified in the NERC Odessa event (and other NERC event reports) and ultimately determine Plan of Service needs. In the System Impact Study phase, not even the OEM has been finalized by the Developer. EMT time-domain simulations study specific controller and relay settings and determine whether those settings would be acceptable for given system conditions and contingencies. Such EMT time-domain simulations do not lend themselves to answering whether there exists an acceptable parameterization such that stable performance can be achieved. As a Transmission Planner, BPA does not anticipate concluding that there exists no controller and relay parameterization that will mitigate stability risks such that a new STATCOM or new line is required. A blanket requirement for a STATCOM is financially burdensome to Developers as well as an inefficient use of material resources and labor. A requirement to change the controller parameterization in the System Impact Study is not interesting because the controller parameterization has not actually been selected. At the time when the controller parameterization has been selected by the developer based on the actual OEM and site specific design (currently this occurs months before the desire to finalize commissioning), it is politically challenging and financially burdensome for the Interconnection Study performer to require the Developer to construct a STATCOM or new line to mitigate instabilities. Additional unexpected capital costs, lead times of over one year, potential realty implications, and the existing loan interest accrued during that extra wait time and others contribute to the financial burden on Developers.

As a result, BPA believes the EMT modeling requirements belong in a separate Guideline or Standard.

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 Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, 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 and BANC

Answer	
Document Name	
Comment	

SMUD and BANC agree with the comments submitted by the American Public Power Association (APPA).

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 additional comments.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	
Comment	

Thank you for the opportunity to comment.

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

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation supports the comments provided by NAGF.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation supports the comments provided by the NAGF

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy thanks the drafting team for their work.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Glen Pruitt - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD Voters	
Answer	
Document Name	
Comment	

The new MOD-026-2 draft appears to remove the provisions in the current MOD-026 R3 and MOD-027 R3 where the Transmission Planner could, apart from the normal testing schedule, notify the Generator Owner of issues regarding the generator excitation or governor model and request a resolution. This takes away an important tool from the Transmission Planner in maintaining usable models. It is recommended those MOD-026 R3 and MOD-027 R3 provisions be maintained to carry forward this function in the new proposed MOD-026-2.

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

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

Answer	
Document Name	

Comment

The NAGF notes that significant additional costs will be incurred with purchasing equipment to perform EMT modeling:

- *A computer outfitted to run EMT modeling software needs significant processing power*
- *EMT software itself is very expensive.*
- *Training engineers in house or consulting out to do the modeling is expensive.*
- *Installing equipment at BES facilities to capture large signal disturbance events is expensive.*

Therefore, the NAGF recommends that the SDT consider having the TPs analyze facilities that pose the greatest risk and let them decide if an EMT model is needed.

Likes 0	
Dislikes 0	

Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	
Document Name	
Comment	
RE: Applicable Facilities – Section 4.2.5: Please add clarity to section 4.2.5 regarding HVDC systems that it only applies to facilities that meet the BES definition. RE: MOD-026-2 Attachment 1 Model Verification Periodicity – Row Number 13: Please consider changing, "Commissioning date of the applicable Facility is before January 1, 2023…" to read as "Commissioning date of the applicable Facility is before the effective date of MOD-026-2…" RE: Active power and active/reactive output: Please consider using the NERC Glossary of Terms definitions of Real Power and Reactive Power throughout MOD-026-2.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
No Comments.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	

Austin Energy disagrees with this posting of MOD-026 due to lack of formal definition for the term Inverter Based Resource (IBR), and believes that this term should be defined within the NERC Glossary rather than in individual Standard language to ensure consistency across Standards.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	
Document Name	
Comment	

Combining MOD-027 and MOD-026 requirements into MOD-026-3 will impose operational difficulties for implementation and execution. There is clarity and management practicality in retaining separate MOD26 and MOD27 standards.

The Validation methodology for Requirements R2, R3, R4, and R5 are still lacking the details, similar to previous revisions of MOD-026 (and MOD-027). The current validation methods can only validate parameters within the model for slow varying events. There are multiple parameters within the power plant controller (and generator) that are applicable to events at less than 1 second level that cannot be validated using traditional voltage or frequency events, e.g., LVRT, HVRT, FFR, etc for IBRs. The standard should provide some practical methodologies to validate at least 80% or 90% of the model parameters. Additionally, the standard should clarify preference and distinction between User Defined Models (UDM) vs. Generic models from OEMs.

SRP recommends separating EMT model validation and development to a different/separate standard. The current draft includes the EMT requirements for IBRs in R6. However, the industry is lacking the expertise for EMTs that require more in-depth guidelines for the Standard. SRP believes a separate standard with detailed information on some of the recommended practices, modeling requirements, validation strategies will be very helpful. In particular, the current draft does not provide practical validation for the EMT model and lacks details on what device test is and how to perform Large single disturbance.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6	
Answer	
Document Name	
Comment	

Austin Energy disagrees with this posting of MOD-026 due to lack of formal definition for the term Inverter Based Resource (IBR), and believes that this term should be defined within the NERC Glossary rather than in individual Standard language to ensure consistency across Standards.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
Currently the drafting committee includes contractors that specialize in the model validation and associated tasks required in this standard. NRG believes there is a Conflict of Interest to have these contractors as part of the drafting team as it is beneficial from a business perspective to require additional requirements that will invoke frequent model validation work, which is what would happen with the current proposed revision. NERC should investigate performing technical studies on how to utilize existing PRC criteria to setup modeling boundaries. This will also benefit the TPs who will not have to consider and address every change from all the GOs.	
Likes 0	
Dislikes 0	
Response	
Desmarie Waterhouse - American Clean Power Association - 4 - NA - Not Applicable	
Answer	
Document Name	
Comment	

The term "inverter-based resource" (IBR) has not been formally defined for use in the NERC Reliability Standards. The SDT should prioritize the creation of a NERC definition for IBR before continuing to move forward in creating new reliability requirements for IBRs. Another alternative is that it may be more efficient to create a standalone Standards Project that addresses the IBR definition development for all future standard changes, similar to Standard Project 2016-02 and Standard Project 2015-09.

However, if the SDT pursues the definition in this standard, the SDT should create a formal definition and not attempt to define it in the footnotes of the Standard. Footnotes in standards should not be used to include part of the requirement to meet compliance. In addition, multiple Standard Projects are utilizing the term IBR, but each Standard Project is using a different definition or using the term IBR in a different context. By not defining IBR, there's a risk of inconsistency between the different standards. Similar comments on the need to formally define IBR were submitted in response to Project 2021-01.

Also, we recommend that the Standards Drafting Team (SDT) use the term "Inverter-based Resource(s)" throughout the proposed revisions to MOD-026-2 instead of "Inverter Based Resource(s)" as the former format is favored by NERC (and industry) in its documentation and reports regarding IBRs.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

The SPP RTO recommends that the MOD-026 drafting team consider coordinating with the MOD-032 and EMT drafting teams to ensure that the data request for the SCR screening as well as the EMT study is consistent and doesn’t create confusion amongst the applicable standards.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Currently the drafting committee includes contractors that specialize in the model validation and associated tasks required in this standard. NRG believes there is a Conflict of Interest to have these contractors as part of the drafting team as it is beneficial from a business perspective to require additional requirements that will invoke frequent model validation work, which is what would happen with the current proposed revision.

NERC should investigate performing technical studies on how to utilize exiting PRC criteria to setup modeling boundaries. This will also benefit the TP who will not have to consider and address every change from all the GOs.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

It is not clear why the SDT added item 4.2.6. under Facilities in the Applicability section of the standard. Any facility meeting an exclusion of the BES definition would already be excluded. It is redundant and unnecessary and not consistent with how applicability sections in the standards are applied.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC 2023

Answer	
Document Name	

Comment

The SRC recommends that the standard be re-titled to: “Validation and Verification of Dynamic Models and Data for BES Connected Facilities.” Based on footnotes 1 & 4, the revised standard appears to cover both topics, not just verification.

The use of the term “verified model” throughout the standard is somewhat confusing, as it typically refers to a model that has undergone “validation” rather than just “verification.” The SRC recommends that the SDT consider removing the “verified” qualifier because the requirements for the submitted model are specified in the sub-requirements (R2.1-R2.4, R3.1-R3-4, R4.1-R4.4, R5.1-R5.4, and R6.1-R6.6). Alternatively, the SDT should consider using a different term or at the very least clarifying the distinction between the use of “verified model” as used in the standard and “verification” as described in footnote 1 or as discussed at the industry webinar (June 2023), as well as clarifying in footnote 1 that “validation” is considered to be a subset or component of “verification.”

The SRC recommends that the SDT consider adding a general sub-requirement of “Model(s) representing all relevant plant/facility settings” to each of the requirements R2 through R6.

The technical rationale should clarify why the SDT added item 4.2.6 under *Facilities* in the Applicability section of the standard. Any facility meeting an exclusion of the BES definition would already be excluded, as it would not fall under any of the other items identified under Facilities. Furthermore, 4.2.6 is not structured using language that parallels the language in 4.2.1 through 4.2.5 and doesn’t fit following the lead-in phrasing from 4.2.

Additionally, the technical rationale should clarify why a specific frequency deviation is specified for R3.4, R5.4 and R6.5 validation, but no specific voltage deviation is specified for R2.4, R4.4 and R6.4 validation.

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

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Tony Hua - Austin Energy - 4

Answer	
Document Name	

Comment

Austin Energy disagrees with this posting of MOD-026 due to lack of formal definition for the term Inverter Based Resource (IBR), and believes that this term should be defined within the NERC Glossary rather than in individual Standard language to ensure consistency across Standards.	
Likes 0	
Dislikes 0	
Response	

Comments submitted by American Transmission Company, LLC

1. Do you agree with the language proposed in MOD-026-2 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☒ No

   Comments: ATC believes that R1 should apply only to the TP (not jointly to TP and PC) so the TP can have wider discretion in writing their process to meet their requirements. The PC could then coordinate and review each of their TPs processes before they are finalized, rather than jointly work on it.

2. Do you agree with the language proposed in MOD-026-2 Requirements R2 and R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☒ No

   Comments: Fundamentally, ATC agrees with these requirements, but before industry could implement all the protection settings for the models (i.e., R2.3 and R3.3) we would need guidance on proper implementation from industry relay vendors. Better modules within the software should be available to use these settings. As it is today, much work needs to be done with Siemens (PSSE), GE (PSLF), PowerWorld, Powertech (DSA Tools), such that commonly used relays from industry vendors such as ABB, SEL, GE, etc. are accounted for in the software packages. These issues need to be addressed before requiring industry to include verification and validation of these settings. The existing software does not readily support these updates for positive sequence dynamic models.

3. Do you agree with the language proposed in MOD-026-2 Requirements R4 and R5? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☒ Yes
   ☐ No

   Comments: None

4. Do you agree with the language proposed in MOD-026-2 Requirement R6? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☒ No

   Comments: ATC generally agrees with R6. More information or a reference on Footnote 12 is required (e.g., tie to other industry standards, such as IEEE, where this is described). Notably, what is meant by “factory type test, hardware in the loop test, or other manufacturer test.”

5. Do you agree with the language proposed in MOD-026-2 Requirements R7, R8, and R9? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☒ Yes
   ☐ No

   Comments: None

6. Do you agree with the language proposed in MOD-026-2 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☒ No

   Comments: All IBR models should be verified **before** new resource interconnection (e.g., the resource goes in service and/or commercial) or before a change is made to the IBR resource. There are many adjustable parameters that may be set and if you verify them all after, the transmission system could possibly be at risk with faulty parameters until the TO can properly review. Validation may take additional time (see question 9 for more).

7. The standard drafting team (SDT) believes the language of MOD-026-2 addresses the issues outlined in the 2 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.

   ☒ Yes
   ☐ No

   Comments: None

8. The SDT proposes a 2-year implementation plan for MOD-026-2 Requirements R1, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 and R7 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained for Requirements R2-R5 from the date of previous model verification. Do you agree with the proposed implementation plan timeframes? If you think an alternate timeframe is needed, please propose an alternate implementation plan with detailed explanation.

   ☒ Yes
   ☐ No

   Comments: None

9. Provide any additional comments on the standard and technical rationale for the SDT to consider, if desired.

   Comments:

   a) The name of the standard should be renamed to incorporate the act of validation as called out in section 6.2. Perhaps the standard can be renamed as, “MOD-026-2 – Verification and Validation of Dynamic Models and Data for BES Connected Facilities.”

   b) Verification of models should occur BEFORE new resource interconnection or changes to a resource are allowed. Then validation should occur on the verified models some time shortly after. In other words, there should be discussion within the standard of verified models separately from validated models and then using a “verified and validated” term to tie the processes together at the end of validation. Both verification and validation need to work hand in hand to inform the process. This might alter the way Attachment 1 is structured as well.

Comments submitted by Sacramento Municipal Utility District and Balancing Authority of Northern California

SMUD and BANC have already submitted comments for Question 2 – those were supporting the comments submitted by Tacoma Power.

Here are our final comments on Questions 7 and 9. I will reach out to APPA and let them know that the comments SMUD and APPA collaborated on were not submitted to prevent this from happening again.

Question 7:

SMUD and BANC believe that the SDT has overlooked the costs related to the purchase of the EMT software, hardware to run the software, and personnel training that will be required to use these relatively new models and studies. NERC has already received more than 700 registration requests for its upcoming EMT Boot Camps which highlights industry's demand for this type of training. More EMT training will certainly be needed for engineers to become proficient in implementing the proposed revisions to MOD-026. Transmission Planners should be the ones who determine which facilities pose the highest risk to the Bulk Power System and decide if an EMT model is required.

Furthermore, on their face the proposed MOD-026-2 changes address the issues outlined in the two SARs in a cost effective manner. However, impending changes from the NERC Inverter-Based Resources (IBR) Work Plan must be considered. Once the NERC IBR Work Plan actions are identified in the next six months, another revision to the MOD-026-2 Applicability Section will be required. This would be inefficient and not cost effective. Posting multiple revisions to the same Standard in a short time period (less than year) is not an efficient or effective use of ERO entities' time. Therefore, we recommend delaying the completion of Project 2020-06 until the scope of the NERC IBR work plan can be included, so only one version needs to be implemented.

Question 9:

The term Inverter-based Resource (IBR) has not yet been formally defined for use in the NERC Reliability Standards. The SDT should prioritize the creation of a NERC definition for IBR before continuing to move forward in creating new reliability requirements for IBRs. Another alternative is that it may be more efficient to create a standalone Standards Project that addresses the IBR definition development for all future Standard changes, similar to Standard Project 2016-02 and Standard Project 2015-09.

However, if the SDT pursues the definition in this standard, the SDT should create a formal definition and not attempt to define it in the footnotes of the Standard. Footnotes in standards should not be used to include part of the requirement to meet compliance. In addition, multiple Standard Projects are utilizing the term IBR, but each Standard Project is using a different definition or using the term IBR in a different context. By not defining IBR, there's a risk of inconsistency between the different Standards. Similar comments on the need to formally define IBR were submitted in response to Project 2021-01.