Comment Report

Project Name:	2020-06 Verifications of Models and Data for Generators | Draft 2
Comment Period Start Date:	11/21/2022
Comment Period End Date:	1/18/2023
Associated Ballots:	2020-06 Verifications of Models and Data for Generators Implementation Plan AB 2 OT 2020-06 Verifications of Models and Data for Generators MOD-026-2 AB 2 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 as a whole that Draft 2 of MOD-026-2 is an improvement to Draft 1? If you do not agree, please provide an explanation.

2. Do you agree 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.

3. Do you agree 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.

4. Do you agree 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.

5. Do you agree 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.

6. Do you agree 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.

7. The 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 1-year implementation plan for Requirements R1, R7, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained 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 on the standard and technical rationale 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
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC
					Daniel Mason	Portland General Electric Co	6	WECC
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC

Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Standards Review Committee	Mike Del Viscio	PJM	2	RF
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Helen Lainis	IESO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Nathan Bigbee	ERCOT	2	Texas RE
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Dave Hartman	Arizona Electric Power Cooperative	1	WECC

					Scott Brame	NC Electric Membership Corporation	3,4,5	SERC
JEA	Joseph McClung	1	FRCC	LPPC	Joe McClung	JEA	1,3,5	SERC
					Tim Kelley	SMUD	1,3,4,5	WECC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO

					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					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
Santee Cooper	Marty Watson	5		Santee Cooper	Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
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
Southern Company - Southern Company Services, Inc.	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC

					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity	2	NPCC

	System Operator		
Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
Randy MacDonald	New Brunswick Power Corporation	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Michael Jones	National Grid	3	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Glen Smith	Entergy Services	4	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC

					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
					Sunny Raheem	Southwest Power Pool Inc	2	MRO
					Lottie Jones	Southwest Power Pool Inc.	2	MRO
					Rebecca McCann	Southwest Power Pool Inc.	2	MRO
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 / 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	Todd Bennett	3		AECI	Michael Bax	Central Electric Power	1	SERC

Cooperative, Inc.						Cooperative (Missouri)		
					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 Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree as a whole that Draft 2 of MOD-026-2 is an improvement to Draft 1? If you do not agree, please provide an explanation.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

The majority of the recommendations and concerns Oncor submitted in the last ballot period were not addressed in this revision.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro appreciate the changes that the SDT made to the Draft-1. However, we still believe the revised draft standard need more clarifications as outlined below.

1) The way it is written, R1.2 always requires TP/PC to develop EMT model requirements irrespective of whether they need such models or not. We believe TP/PC should have the flexibility to determine the level of detail of EMT models and when it is required. This is the language that we can see in Part 1.2 of the Technical Rationale document. Such an important requirement should be clearly specified within the standard rather than referring to supplementary technical documents.

2) Draft 2 does not address the simulation tool's modeling capabilities to avoid the need for developing user's defined models (which may add a lot of complexity and overhead to developing these models with some level of approximation. It is more difficult to share user's defined models with other PCs and more difficult to maintain and validate the user's defined models).

3) Draft 2 does not encourage dialogue between entities to ensure a cost-effective manner to meet the TP/PC required modeling details. Adding more details such as more protection elements to the minimum modeling requirements without considering the actual TP/PC modeling details requirements, type of studies and studies issues is not the right way to go. It should be left up to the TP/PC to communicate to the generator and transmission owners the minimum modeling requirements to address their concerns and needs.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	No
Document Name	
Comment	
Changes to R7 make it less clear on the scope of changes that requires a new model. However, the changes to R8 are welcomed improvements.	
Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

Combining governor modeling and excitation modeling into the same standard is less efficient in practice than keeping MOD-026 and MOD-027 separate from both an operational and administrative perspective.

Operational Considerations:

For existing facilities, governor systems and excitation systems are often changed, replaced, or tested independently. Therefore, throughout the implementation of MOD-026-1 and MOD-027-1, governor system modeling and excitation system modeling has been tracked and managed very independently. From an operational perspective, there is no efficiency gain from combining MOD-026-1 and MOD-027-1.

Administrative Considerations:

Presently, the entire industry has established compliance and internal controls programs to track the implementation of MOD-026-1 and MOD-027-1 independently. Enterprise work order management systems, work practice guidelines, and compliance tracking tools have been established to address excitation modeling per MOD-026-1 and governor modeling per MOD-027-1. Combining MOD-027-1 and MOD-026-1 will introduce an immense administrative burden resulting from the need to restructure the compliance programs that have already been established.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

· The MRO NSRF appreciates the SDT's goal of moving industry forward in a new and technical area.

· However, the MRO NSRF must pragmatically break the goal of developing EMT models down into manageable steps to be fully compliant.

· The SDT revision to 36 months is not sufficient.

· Fundamentally, industry is resource limited as there aren't a sufficient number of EMT experts.

· Industry must have at least 60 months to purchase software, train personnel and verify models. This is still an aggressive goal at 60 months.

The MRO NSRF appreciate the changes the SDT made. However, important structural changes suggested by the MRO NSRF in draft 1 were not adopted.

Key structural concerns included:

· R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn't provide the TP with the flexibility to determine when EMT models are required.

· For R1.2, while the technical rationale states that R6 limits the number of EMT models, there is no language within MOD-026-2 that states this. The MRO NSRF recommends that additional language be added to R1.1 and R1.2 to state EMT models "where determined and in accordance with the PC and TP joint model process in the requirements".

· With regard to Part 1.2, the MRO NSRF requests NERC or other industry group develop an acceptable list of electromagnetic transient (EMT) models. Industry has little expertise with EMT. A list of acceptable models, similar to positive sequence models, will reduce barriers and speed EMT model development for applicable functional entities; e.g. Planning Coordinators and Transmission Planners. EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint.

· Clarifying "Facility". The MRO NSRF suggests the following changes to clarify:

4.2.1 For the purpose of this standard, the term "applicable Facility or Facility" subject to these requirements means:

4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or

4.2.1.2: BES generating "plant" at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

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 MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	

Comment

{C}· The MRO NSRF appreciates the SDT's goal of moving industry forward in a new and technical area.

{C}· However, the MRO NSRF must pragmatically break the goal of developing EMT models down into manageable steps to be fully compliant.

{C}· The SDT revision to 36 months is not sufficient.

{C}· Fundamentally, industry is resource limited as there aren't a sufficient number of EMT experts.

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Key structural concerns included:

{C}· R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn't provide the TP with the flexibility to determine when EMT models are required.

{C}· For R1.2, while the technical rationale states that R6 limits the number of EMT models, there is no language within MOD-026-2 that states this. The MRO NSRF recommends that additional language be added to R1.1 and R1.2 to state EMT models "where determined and in accordance with the PC and TP joint model process in the requirements".

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{C}o 4.2.1 For the purpose of this standard, the term "applicable Facility or Facility" subject to these requirements means:

{C}§ {C}4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or

{C}§ 4.2.1.2: BES generating “plant” at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	

Comment

In order to ensure consistent EMT models are developed and implemented and that adequate EMT simulation tools are used IID planners will require time to be trained on EMT models, simulations and their corresponding tools and software. IID Transmission Planners are following regional group efforts that may standardize things such as model formats and acceptable software

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's Comments which state:

While the changes made to MOD-026-2 are an improvement, we still do not support Draft 2 because of the concerns described in our responses to Questions 2, 5, 6 & 9 .

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP appreciates the efforts of the Standards Drafting Team, it does not appear that most of the recent edits are substantive. So, while certainly not objectionable, we do not view the latest draft as a step forward or improvement of its predecessor.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
While BPA agrees that the NERC MOD-026 and MOD-027 standards need revising, BPA believes the SDT has overstepped the scope of the SAR by adding EMT models to the Verification of Models and Data for Generators in this draft.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	
Comment	
Minor editorial comments incorporated in Draft 2 do not address overall Duke Energy and industry comments or concerns.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	

Comment	
Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
Per the BES definition of Inclusion I5, the rating is 100 kV and additionally, other inclusion references rating “aggregate of 75 MVA or greater”. See additional comments from the NAGF for question 6 & 8.	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
The main concerns for SIGE surrounding EMT models were not addressed during this revision.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

While AZPS agrees that many changes were made between drafts 1 & 2, AZPS does not agree that changes were made to issues that AZPS finds most significant. AZPS has provided addition information in its responses to questions 2 through 9 below which describe these issues in detail.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
The challenge with this standard is that most of inverter based interconnected Generation does not have a Transmission Planner. As a result of their absence of skill set in this area, the models that we get are incompatible with our region models.	
Likes 0	
Dislikes 0	
Response	
Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	No
Document Name	
Comment	
Constellation agrees and appreciates the consideration on allowing excitation and governor modeling to be completed separately. However, Constellation has additional concerns with the additional requirements around protection system components and potential additional costs remain. Kristine Howie on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation agrees and appreciates the consideration on allowing excitation and governor modeling to be completed separately. However, Constellation has additional concerns with the additional requirements around protection system components and potential additional costs remain. Alison Mackellar on behalf of Constellation Segments 5 and 6	
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 comments to Question 3.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	No
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (“CEHE”) appreciates the changes that the SDT made to the Draft-1. However, CEHE does not support Draft 2 because the majority of the recommendations and concerns submitted by CEHE in the last ballot period were not addressed in this revision.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon concurs with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
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 supports the comments submitted by EEI	
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	

Changing “Applicable Facilities” to those defined in the BES definition can result in a change in the scope of the standard without modification of the standard if the BES definition changes. This does not align with analysis and identification of a facility as a reliability risk. The BES definition will likely always move in the direction to include smaller units at lower interconnection voltage and may not be based on reliability concerns. This change can increase the scope of Applicable Facilities without justification of the scope increase. We suggest the following changes to 4.2.1 to clarify the term “applicable Facility or Facility” using:

- 4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or
- 4.2.1.2: BES generating “plant” at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

I do not agree with the combining of Mod-26 and Mod 27. Although process and requirement language have basic commonalities across the two standards, MOD26-1 covers generator excitation system testing and modeling and MOD27-1 covers Turbine speed governor control system testing and modeling. These systems are unique to each system’s function, testing is wholly unique to each system, and models are wholly unique to each system. Testing may be staged separately, might be performed by different testing entities and model verification is evaluated for compliance for each on a separate basis. There is definitive clarity and management practicality in retaining separate MOD26 and MOD27 standards

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

While the SDT made some clarifying improvements to the current draft, many of the issues identified in draft 1 remain. Please refer to the below comments.

Likes 0	
Dislikes 0	

Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Many of the technical concerns that were identified in first draft were not adequately addressed in second round.	
Likes 0	
Dislikes 0	
Response	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The new requirement for EMT models represents a significant burden on Generator Owners. Additional models need to be developed, tested, and validated. There are limited resources available who can provide these services. Manufacturers may face challenges being able to provide PSCAD models for equipment that is no longer supported or in production.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The SDT revision to 36 months is not sufficient. Fundamentally, industry is resource limited as there aren't a sufficient number of EMT experts. Industry must have at least 60 months to purchase software, train personnel and verify models. This is still an aggressive goal at 60 months. NVE appreciates the changes the SDT made.	

Key structural concerns included:

R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn't provide the TP with the flexibility to determine when EMT models are required.

For R1.2, while the technical rationale states that R6 limits the number of EMT models, there is no language within MOD-026-2 that states this. NVE recommends that additional language be added to R1.1 and R1.2 to state EMT models "where determined and in accordance with the PC and TP joint model process in the requirements".

With regard to Part 1.2, NVE requests NERC or other industry group develop an acceptable list of electromagnetic transient (EMT) models. Industry has little expertise with EMT. A list of acceptable models, similar to positive sequence models, will reduce barriers and speed EMT model development for applicable functional entities; e.g. Planning Coordinators and Transmission Planners. EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint.

Clarifying "Facility". The NVE suggests the following changes to clarify:

4.2.1 For the purpose of this standard, the term "applicable Facility or Facility" subject to these requirements means:

4.2.1.1 A BES generator with a gross individual nameplate rating greater than 20 MVA connected at 100 kV and greater; or

4.2.1.2: BES generating "plant" at the common Point of Interconnection meaning the transmission (high voltage) side of the main generator step-up transformer where more than 75 MVA of aggregate generation has been collected connected at 100 kV and greater. Individual generating resources below the common point of interconnection are excluded.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC

Answer	Yes
Document Name	

Comment

No additional comments.

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 has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees that Draft 2 is an improvement but feels there are additional items that need to be resolved which are identified in our responses to the remaining questions.	
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	
Donald Lock - Talen Generation, LLC - 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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1

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	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
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	

2. Do you agree 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.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP suggests that the drafting team take into consideration revising Requirement R1 as well as the Technical Rationale to include language that shows that the MOD-032 Standard assists the PC in the data collection process to build the dynamic and EMT models. From our perspective, the proposed language suggests that the PC is using MOD-026-2 to assist in the model build, but this standard is more applicable to the TP which may create some confusion around the modeling process.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The addition of “within 90 days of receiving a written request” in R1.6 is not a reliability based objective. NERC continues to add compliance administration to the requirements that have little to zero actual reliability benefits. NVE recommends no change or “in accordance with the TP process.”	
Likes 0	
Dislikes 0	
Response	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The new requirement for Electromagnetic Transient models requires significant effort and investment to meet. Obtaining PSCAD models for legacy equipment can be challenging or impossible depending on the level of support from the equipment manufacturer. Many of our windfarms are older than 10 years utilizing technology no longer in production.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Excitation Limiters and Protection System elements are not dynamic model elements; therefore, should not generically refer to them as elements of a dynamic model.

The requirement continues to give the Transmission Planner and Planning Coordinator the ability to implement their own methods, requirements, processes, and acceptance criteria without constraints, boundaries, or need of consistency with other industry participants.

The requirement should establish a technical criterion as part of the standard revision and let the planners make local necessary adjustments as necessary. This will allow the GOs to have a say in what is required before the requirement becomes a mandate.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

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 Operations time horizon does not appear appropriate for this type of long term coordination between the Transmission Planner and Planning Coordinator.

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

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

- R1 still requires EMT models at all times without deferring to when the TP or PC requests them. While footnote 2 discusses the level of detail, it doesn't provide the TP with the flexibility to determine when EMT models are required. EMT models should only be required for resources which are specifically identified within Requirement R6, commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC.
- For R1.2, while the technical rationale states that R6 limits the number of EMT models, there is no language within MOD-026-2 that states this. Southern Company recommends that additional language be added to R1.1 and R1.2 to state EMT models "where determined and in accordance with the PC and TP joint model process in the requirements". Important requirement details cannot be left in the technical rationale.
- Southern Company continues to have concerns that combining MOD-026 and MOD-027 could in effect make Primary Frequency Response (PFR) retroactive by stating models must be developed in R3. We suggest that the Standards Drafting Team (SDT) add the words "in accordance with FERC Order 842" to R3 to clarify and differentiate between generators that are and are not required to have PFR.
- With regard to Part 1.2, we request that NERC or another industry group develop an acceptable list of electromagnetic transient (EMT) models. Industry has little expertise with EMT. A list of acceptable models, similar to positive sequence models, will reduce barriers and speed EMT model development for applicable functional entities; e.g. Planning Coordinators and Transmission Planners. EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint.
- The addition of "within 90 days of receiving a written request" in R1.6 is not a reliability based objective. This adds compliance administration to the requirements that have little to zero actual reliability benefits. We recommend either no change or "in accordance with the TP process."

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 supports the comments submitted by EEI

ITC has the following additional comments:

ITC is concerned that for R1 the verification parameters must be jointly determined by the Transmission Planner and the Planning Coordinator. However, all of the studies will be performed by the TP who may be provided with a set of parameters that are a one size fits some within

the PC area and set for all TPs within the area and may not apply to all systems within the region. The PC could push for complicated and/or rigorous procedures if they are not actually doing the work. Since the actual validation work is done by the TP, except for those TP's who have delegated TP functions to the PC. Let the TP identify the validation parameters and unless the PC can justify why they are unacceptable and should be changed.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
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	
PGAE proposes an additional modification to Section 1.2 to help clarify what it applies to and when (mod/adds in bold): 1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only and commissioned after the approval date of this Reliability Standard.**	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	

Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

The terms used in Requirement R1, 1.3 should be supplemented with practical guidance. For example, additional language could be added to supplement the term “parameterization checks” to clarify that the term is meant to validate model parameters and settings against the actual field equipment. Similarly, additional language could be added to supplement the term “interoperability” to indicate that models must be tested in a full case to determine general problems such as crashing, inability to handle certain time steps, and/or acceleration factors. and to indicate that both types of models (positive sequence and EMT models) should produce the same results when they operate on different software platforms.

Regarding proposed Requirement R1.3, attempting to test initialization and interoperability in a full EMT case would require a fundamental change for Transmission Planners and the PC within ERCOT footprint. It would be more efficient and cost effective for Transmission Planners to validate the EMT models with a simpler, controllable infinite bus test rather than validating them through a full EMT case. Thus, CEHE suggests revising the proposed Requirement R1.3 to allow TPs to use the alternative method to validate the EMT models.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

- Acceptable positive sequence dynamic Model list and level of detail should come from NERC ERAG /MMWG.
- Acceptable EMT Model list and level of detail should come from NERC ERAG /MMWG.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #2.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	
Comment	

On behalf of the SERC Generator Working Group (GWG):

Suggest adding to footnote 1 (and everywhere this footnote is) "existing" in front of documents and files

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	

Regional enforcement authorities lack the enforcement authority for inverter-based interconnected Generation utilities to get a Planning Coordinator or enforced the new modeling requirements.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

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 why it is needed. Concerns for large-signal disturbance behavior are already being addressed by recommended practices such as 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. Since 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 to 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.

AZPS does not agree with the inclusion of subpart 1.3.1. Previous MOD 026 model criteria was intentionally vague in order to leave room for engineering judgement when conducting the model validation. No model is a facsimile of reality, and there needs to be room for creating a model that adequately reflects reality based on the judgement of the person conducting the model validation. For this reason, AZPS requests further information regarding the intent of subpart 1.3.1 as the example provided in the Technical Rationale is not comprehensive.

AZPS also supports the following proposed edits shown in bold submitted by EEI for Requirement 1, Part 1.2:

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only, and commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC**;

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 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

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

Answer	No
Document Name	

Comment

R1.2 EMT models are not used by most Transmission Planners. This addition will add significant cost to generation owners. The EMT models requirement should be listed as optional and only be provided based on appropriate justification and on a case-by-case basis. The financial impacts to generator operators to provide these models for every applicable facility is not justified. Positive sequence generic models if properly populated and verified are adequate for most transmission studies. The transmission software tools to study the entire system with EMT models do not exist.

Requirements should be detailed in this standard. Utilities that operate in multiple regions will be required to submit different levels of detail to comply with this Standard. The wording in R1.1, R1.2, and R1.3 gives the TP authority to request data above the needed intent of the Standard (Performance

Curves, Response Characteristics, Response Times, etc.). R1 should be modified to read:…The dynamic model verification requirements and processes shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner, and include based on technical justification, the following:

The specific acceptance criteria for the model in R1.1, 1.2 and 1.3 should be developed by the industry modeling experts or remain the same as existing MOD-026 and MOD-027 standards.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

NERC MOD-026-1 and MOD-027-1 standards cover models used in BES level studies, while EMT models are used for specialized equipment studies. BPA does not believe it is appropriate to require EMT model validation as a part of these NERC Reliability Standards. BPA recommends a Reliability Guideline be developed, reviewed, and approved by the industry, PRIOR to making a sweeping change(s) pertaining to EMT Models in NERC Reliability Standards. This would allow industry an opportunity to fully understand the concepts of EMT model validation, outside of a FERC approved implementation plan.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

Requirement R1 addresses “dynamic model verification requirements and processes”, but Part 1.2 addresses EMT models, which are generally distinguished from “dynamic models”. While it may be possible to adjust the Requirement R1 language to be inclusive of dynamic models and EMT models, it seems cleaner to separate TP/PC EMT model verification requirements and processes into a separate requirement.

Likes 0	
Dislikes 0	

Response

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

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

FirstEnergy supports EEI's Comments which state:

EEI does not support the proposed language for R1 because (see comments below and suggested edits to Requirement R1 in boldface):

· R1.2 is insufficiently clear as to EMT requirements. While Footnote 2 provides clarity, clarifications contained in footnotes are often missed. EEI suggests language that we believe generally aligns with SDT intent but is not contained in a footnote.

· R1.6 does not provide sufficient time for GOs and TOs to obtain models needed by the TP and PC. We suggest 180 days.

R1. Each Transmission Planner and its Planning Coordinator, shall jointly develop dynamic model verification requirements and processes. The dynamic model verification requirements and processes shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner, and include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

1.1. Acceptable positive sequence dynamic models, format, and level of detail;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only, and commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC**;

1.3. Acceptance criteria used by the Transmission Planner to determine disposition under Requirement R8 including , at a minimum , the following:

1.3.1. model parameterization checks;

1.3.2. model usability, initialization, and interoperability; and

1.3.3. model submittal requirements.

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

1.5. Process by which verified model(s) are submitted to the applicable Planning Coordinator, after the model(s) meets acceptance criteria of Part 1.3; and

1.6. Process for Generator Owner or Transmission Owner to obtain the model(s)contained in the Transmission Planner's database for an existing Facility owned by the Generator Owner or Transmission Owner within **180** days of receiving a written request

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	

Comment

The addition of "within 90 days of receiving a written request" in R1.6 is not a reliability based objective. NERC continues to add compliance administration to the requirements that have little to zero actual reliability benefits. The MRO NSRF recommends no change or "in accordance with the TP process."

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 both the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC

Answer	No
Document Name	

Comment	
PNM Resources recommends the Planning Coordinator be removed from requirement R1. MOD-032 addresses modeling requirements and communication of models to the Planning Coordinator. Given the confidentially around EMT modeling it will be difficult to provide EMT models to a Planning Coordinator. With the limitations of EMT modeling on large system, it probably doesn't make sense to require both Planning Coordinator and Transmission Planner to keep EMT modeling data.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The addition of "within 90 days of receiving a written request" in R1.6 is not a reliability based objective. NERC continues to add compliance administration to the requirements that have little to zero actual reliability benefits. The MRO NSRF recommends no change or "in accordance with the TP process."	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
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 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. Furthermore, the changes unnecessarily pull in requirement activities for the Planning Coordinator (the standard incorrectly references Planning Authority, which NERC has moved away from); under MOD-032, the Planning Coordinator has the opportunity to work with the Transmission Planner on data items; the approach for this 'TP Model Spec and Process' as found in the current MOD-026 and MOD-027 standards are preferable to this new language. Furthermore, while the current standards specify a minimum and appropriate level of initialization tests and criteria, the new standard does not, which could lead to poor acceptance testing by the Transmission Planner.	

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	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Why do the dynamic model verification requirements and processes need to be jointly developed with the planning coordinator since the transmission planner is solely responsible for the verification studies?	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Please refer to item 1) comment provided in Q1.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	

Answer	No
Document Name	
Comment	

Based on the existing generation interconnection process in ERCOT, we recommend changing “Transmission Planner” to “Transmission Planner or Planning Authority” throughout R1 and its sub-requirements. In ERCOT as well as other regions, there are instances in which the Transmission Owner and the Transmission Planner are the same entity. The spirit of the proposed requirement suggests a collaboration of checks and balances to verify modeling accuracy. Requiring a Transmission Owner to send modeling information to itself would not achieve the intended verification of modeling accuracy. Therefore, we advise adding “Planning Authority” in conjunction with “Transmission Planner” for all instances in R1.

The terms used in sub-requirement 1.3 should be clarified with practical descriptions. Please elaborate specifically on the following: “parameterization checks” and “interoperability.” Definitions should be applicable and meaningful to practical Planning studies. It is recommended that the descriptions would be useful in understanding how to benchmark the quality of the models.

Regarding “parameterization checks,” is this analysis intended to be similar to a PSSE DOCU check where each parameter is compared to a typical range? This would be difficult to achieve on User defined models since DOCU ranges are not given for each parameter. Alternatively, are “parameterization checks” meant to validate model parameters and settings against the actual field equipment? Please clarify.

Regarding “interoperability,” does this term indicate that models must be tested in a full case to determine general problems such as crashing, inability to handle certain time steps and/or acceleration factors? Alternatively, does “interoperability” indicate that both types of models (positive sequence and EMT models) should produce the same results when they operate on different software platforms? Please clarify.

Regarding proposed R1.3., attempting to test initialization and interoperability in a full EMT case would require a paradigm shift for Transmission Planners and the Planning Authority within ERCOT. ERCOT does not develop or maintain an official PSCAD case for its Transmission Planners. Cases would need to be built for small individual areas, which would require a substantial undertaking. Instead, it would be more efficient and cost effective for Transmission Planners to validate the EMT models with a simpler, controllable infinite bus test rather than validating them through a full EMT case. Thus, we suggest revising proposed R1.3 to allow Transmission Planners within ERCOT to use this alternative method to validate the EMT models.

Likes 0	
Dislikes 0	
Response	

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
While the SRC generally agrees with the revised language, we have provided some suggestions for R1 under the response to Question 9, below.	
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	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed Requirement R1 modifications.	
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	

Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie

Answer	Yes
Document Name	
Comment	

Constellation agrees with the proposed language, however feels the 90 day requirement under R1.6 is duplicative to R8.

Kristine Howie on behalf of Constellation Segments 5 and 6

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	

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

Answer	Yes
Document Name	
Comment	
BC Hydro suggests the term “90 days” in R1.6 is changed to “90 calendar days” for clarity and consistency with the language used in other Requirements.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections to the language proposed for R1.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
The Impacts to R1.2 requiring EMT models will likely impact TP staff in the future. As of now the GO for IBRs are responsible for the EMT models, however interconnect request may require Avista TP assessment and validation as part of the interconnect assessment. Also in the future if we build wind as a GO or take over and existing wind farm as the new GO upon contract expiration and/or termination, significant SME resources will be required to meet this new EMT requirement.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	

Answer	Yes
Document Name	
Comment	
The Impacts to R1.2 requiring EMT models will likely impact TP staff in the future. As of now the GO for IBRs are responsible for the EMT models, however interconnect request may require Avista TP assessment and validation as part of the interconnect assessment. Also in the future if we build wind as a GO or take over and exiting wind farm as the new GO up[on contract expiration and/or termination, significant SME resources will be required to meet this new EMT requirement.	
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	
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	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
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	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
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	
James Baldwin - Lower Colorado River Authority - 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	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Although BHC agrees with the proposed, it is felt a potential for exceptions on older units may be needed depending upon the criteria of a model as specified by the TP. This may result in a need for a longer implementation if all Facilities are expected to meet the criteria.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree 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.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

As proposed, R2 and R3 each contains a list of information that verified models and accompanying information “shall include at a minimum.” Consider revising that statement to read as follows: “*As applicable*, the verified model(s) and accompanying information shall include, but are not limited to, the following . . . .” This revision would address those instances in which such modeling parameters do not exist. For example, proposed R2.2., R2.3., R3.2. and R3.3. require information related to protection elements. The model components should only be required to include that information if the corresponding device or protection elements exist in the field.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

It looks like the SDT added more relay elements to the requirement R2.3. MH previously mentioned that this requirement is too prescriptive and some of these relay models may not be available in standard library models developed for positive sequence simulation tools. We believe 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.

The level of detail and minimum requirements may change based on the type of studies 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.

Does not encourage dialogue between entities to ensure a cost-effective manner to meet the TP/PC required modeling details. Adding more details such as more protection elements to the minimum modeling requirements without considering the actual TP/PC modeling details requirements, type of studies and studies issues is not the right way to go. It should be left up to the TP/PC to communicate to the generator and transmission owners the minimum modeling requirements to address their concerns and needs.

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
R2 and R3 in particular also appear to have new material beyond the scope of changes presented in the SARs for the MOD-026/27 standard revision. In particular, protection system items found in the new proposed MOD-026-2 R2.1, R2.3, R3.1, and R3.3. all appear to add new requirements not found in the current standards or in the SARs. While information on protection systems is indeed useful to Transmission Planners, such additions should follow the NERC process. Furthermore, this would appear to interfere with provisions in MOD-032 which allow for requesting of such data. Additionally, not all generators have these types of listed (required) protection to model; lastly, the requirement is a general statement “Model(s) representing enabled Protection Systems that directly trip…”. However, under R3/R4 of the proposed standard, these generator response models are clearly intended to be positive sequence models. Thus, relay models for such things as ground protection, negative sequence, phase imbalance, etc. are clearly unsuitable for modeling in a positive sequence model environment; therefore, the SDT should consider revising this to limit the relay modeling scope to only those relays that are appropriate for the positive sequence environment, and that are supported by the Transmission Planner’s study software. Such generator protections can also exist on the generator step-up transformer or generator tie line, further (and unsuitably) expanding the scope of the new proposed protection system modeling requirements.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Requirement R2 2.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
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 MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
Requirement R2 2.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

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-026-2 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, we do not believe the proposed inclusion of protection model data verification and collection in MOD-026-2 would result in meaningful contribution to improving the reliability of the BES.

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

• Stator overcurrent – Not universally applied on synchronous units but if applied, it is likely a limiter or alarm only, not a trip function. As a limiter, it would have an inverse time characteristic likely to extend beyond normal simulation durations.• Field overcurrent – Backup to the over-excitation limiter/maximum excitation limiter (OEL/MXL). It is not necessary to model the trip function as long as the limiter is active.

• Loss of field – No precedent for an excitation equipment failure contingency exists in a standard or in past practice to warrant modeling of this protection. Loss-of-field protection is coordinated with the UEL/MEL for out-of-step operation and loss of excitation due to equipment failure. It is not necessary to model the trip function as long as the limiter is active.

• 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.

• Phase-distance – AEP is unsure why this has been added in Draft 2, and requests insight from the SDT as to their motivations for doing so.

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

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	No
Document Name	
Comment	

RF recommends minimum dynamics modeling requirements (including any necessary minimum Protection System modeling requirements) be specified in MOD-032 Attachment 1. The TP or PC can request other necessary modeling information as needed, but it is useful for Registered Entities and Compliance Enforcement Authorities if MOD-032 Attachment 1 provides a one-stop shop for the ERO-wide minimum modeling requirements.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

R3.3 is covered under NERC Reliability Standards PRC-019 and PRC-024. BPA believes adding R3.3 is redundant.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

The limiter models in PSSe may not be able to accurately represent all manufacturers functions. The standard needs to acknowledge this deficiency and specifically state that dynamic response matching simulations for limiters is not required to be submitted.

Protection models are in no way required if limiters are being used in the models. Protection works in the systems even if the limiters don't. In simulation, this scenario would never occur so there is no need to submit them. PRC standards are already developed to comply with ride-through requirements. This requirement is also pushing generator owners to purchase PSSe or PSLF software or to strictly rely on vendors to perform all this work.

Recommended changes:

1. Remove the need to supply protection models.

2. Make PRC-019 and PRC-024 documents available to TPs so they can populate models as needed.

3. Specify that simulated response of limiter models do not need to match test data for limiters.

a. Simply provide limiter settings for OEL, UEL, V/Hz, and SCL and allow the TP to determine study impacts, or industry could develop simplified limiter models for use with setpoints.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

Rewrite section 2.3 to include the added words in bold:

"Model(s) representing enabled excitation limiters and **model(s) representing** enabled Protection Systems that directly trip the prime mover or generator/synchronous condenser. Protection Systems that shall be modeled include phase over- and undervoltage, stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, loss of field, out-of-step, phase-distance, and volts per hertz protection; and"

As currently written with the “and” between “excitation limiters” and “enabled Protection Systems,” it can be interpreted that only excitation limiters that directly trip the prime mover need to be modeled. Excitation limiters should always be modeled.

Likes 0	
Dislikes 0	

Response

Anna Todd - Southern Indiana Gas and Electric Co. - 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

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
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 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 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. This information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	No
Document Name	
Comment	

Constellation appreciates the clarification that models do not need to be completed simultaneously, however, does not agree with the expanded requirements for modeling requirements. While we understand there may be value in developing and providing a model for non-linear protection functions, We don't see the value in developing models for definite-time relay settings rather than just providing those settings.

Kristine Howie on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation appreciates the clarification that models do not need to be completed simultaneously, however, does not agree with the expanded requirements for modeling requirements. While we understand there may be value in developing and providing a model for non-linear protection functions, We don't see the value in developing models for definite-time relay settings rather than just providing those settings.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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 supports the comments submitted by LPPC.

Tacoma Power is concerned on the potential impact of adding new protection elements to MOD-026 for synchronous generation. Existing modeling software may be capable of modeling these new protection elements, but these models are untested and will need to be tested to have full confidence in the results. Additionally, these models are not currently used in any WECC cases, and would require significant coordination throughout the ERO to standardize the cases. In order to understand the benefit and purpose of modeling protection elements for synchronous generation, Tacoma Power requests additional justification from the SDT describing the benefits of this work and why the PRC Standards are not sufficient.

It would take a significant time investment to provide the setting data and translate it into a format that would be usable for these models.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

R2: For synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

At section 3.3, “Protection Systems that shall be modeled include over- and under-frequency elements” seem redundant with “model(s) representing enabled prime mover over- and under-speed trip functions”. Remove redundancy or provide more information to differentiate both requirements.

At section 3.4, a note explaining what “validation” means should be added, similar to section 2.4.

Likes 0	
Dislikes 0	

Response

Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC

Answer	No
Document Name	

Comment

At section 3.3, “Protection Systems that shall be modeled include over- and under-frequency elements” seem redundant with “model(s) representing enabled prime mover over- and under-speed trip functions”. Remove redundancy or provide more information to differentiate both requirements.

At section 3.4, a note explaining what “validation” means should be added, similar to section 2.4.

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

R2: For synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE disagrees with including the proposed Requirements R2.3 and R3.3 as minimum modeling requirements. The TP and its PC should jointly determine the required minimum modeling requirements and level of the modeling details as stated in Requirement R1.1. If the TP and PC determine that some or all of these listed minimum requirements are needed for the model or the type of studies performed, they can include such requirements as part of the R1.1. The level of detail and minimum requirements may change based on the type of studies and issues the TP is trying to solve. The model requirements and level of detail for the new facilities may differ for new facilities and some in-service facilities. Therefore, the model(s) level of detail should be determined by the TP and PC.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

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 indicates the models identified in Requirements R2.3 and R3.3 should only be required if they are required by the Transmission Planner and simplified. Please see the example of proposed modifications to the R2 language below (mod/adds in bold):

R2. For synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1, each Generator Owner or Transmission Owner shall provide a verified positive sequence dynamic model(s) with associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1. The verified model(s) and accompanying information shall include at a minimum the **following from 2.1-2.3, and if applicable the model(s) listed in 2.4 as determined to be required by the Transmission Planner in R1:** [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Manufacturer, model number (if available), and type of generator/synchronous condenser, excitation system hardware, and Protection System(s) specified in Part 2.3;

2.2. Model(s) representing the generator/synchronous condenser, and associated excitation system including voltage regulator, impedance compensation, power system stabilizer, and outer-loop controls which impact dynamic volt/voltampere reactive (VAR) performance;

2.3**. Validation of the positive sequence dynamic model(s) of Part 2.2 response using the recorded response for a dynamic reactive power or voltage event from either a staged test or a measured system disturbance.**

2.4. Model(s) representing enabled excitation limiters and enabled Protection Systems that directly trip the prime mover or generator/synchronous condenser. Protection Systems that shall be modeled include phase over- and undervoltage, stator-phase overcurrent, voltage restrained time overcurrent, field overcurrent, loss of field, out-of-step, phase-distance, and volts per hertz protection.

The above should also be applied to R3 in a similar manner.

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

Requirement R2 2.3 and R3 3.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating the dynamic behavior of control systems.

Clarify in R2 that it is for excitation/voltage control/var control systems and in R3 that it is for frequency/MW/governor control systems. Reading R2 and R3 alone without the sub parts of each make it difficult to understand what dynamic behavior is to be modeled.

Likes 0	

Dislikes 0	
Response	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
R2 2.3 covering protection system modeling is crossing over ground already in PRC standards, PRC19 and PRC24. This is also requiring contributed input from yet other new entities not previously involved in mod26 compliance.	
Likes 0	
Dislikes 0	
Response	
Joseph McClung - JEA - 1, Group Name LPPC	
Answer	No
Document Name	
Comment	
Large Public Power Council (LPPC) disagree with the proposed language. LPPC members have expressed the view that Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. They point out that this information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.	
Likes 3	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; Austin Energy, 6, Mrini Imane; JEA, 3, Williams Marilyn
Dislikes 0	
Response	
John McCaffrey - American Public Power Association - 4 - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The American Public Power Association (APPA) disagrees with the proposed language. APPA members have expressed the view that Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. They point out that this information is already provided in	

PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Requirement Subpart R2.3 and R3.3 should not require models to contain limiters and protection settings. This information is already provided in PRC-019, PRC-024, and PRC-026, and is not necessary for validating dynamic behavior of control systems. If these subparts to R2 and R3 are kept in the next draft, then more detailed justification and rationale for how protection settings are necessary should be provided in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

Requirements R2 and R3 are almost identical. It is recommended they be grouped into one requirement.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

In R2.3, if a generator doesn't have one of those protection devices then there should be no model requirement

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Limiters and Protection are not dynamic model elements. PRC standards' established limitations should generically be used by the TP to establish modeling boundaries. The absence of a relay protection trip does not make every non-trip operating region acceptable for a generator. PRC protective relay setting criteria have pushed boundaries beyond conservative protection limits for increased system reliability. If planning criteria has no restrictions other than the limits of an individual generator's protective trip, it goes too far. Rather than establishing operating boundaries based upon the Generator trip settings, Transmission Planners need to understand and implement planning criteria consistent and lower than PRC protective relay setting boundaries. For example, there is no technical reason to make plans for operation outside the no-trip boundaries of PRC-024, regardless of where the generator protection is set.

To achieve a more effective means to implement, the industry should first develop acceptable, consistent methods for the TP to receive excitation limiter and protection device setting characteristics. Then, the TP can develop models as needed or justified. The GO should not have the obligation to develop limiter or protection validated models for the TP.

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 / BANC

Answer	No
Document Name	

Comment

SMUD and BANC support the comment of LPPC.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Requirement R2 2.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.	
Likes 0	
Dislikes 0	
Response	
Michael Dieringer - Austin Energy - 3	
Answer	No
Document Name	
Comment	
Austin Energy supports LPPC comments	
Likes 0	
Dislikes 0	
Response	
Tony Hua - Austin Energy - 4	
Answer	No
Document Name	
Comment	
Austin Energy supports LPC comments	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports the revised language in R2 and R3.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro suggests that the wording in Requirement R2 Part 2.3 and Requirement R3 Part 3.3 be adjusted to include enabled Protection Systems that trip the prime mover or generator/synchronous condenser via lockout or auxiliary tripping relays. This is also consistent with PRC-005-6 Section 4.2 Facilities. Please see R2 Part 2.3 suggested wording for drafting team's consideration: "Model(s) representing enabled excitation limiters and enabled Protection Systems that trip the prime mover or generator/synchronous condenser *either directly or via lockout or auxiliary tripping relays."*	
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	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
On behalf of the SERC GWG, suggest clarifying that R2 is for excitation systems and R3 is for governor controls	
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 Requirements R2 and R3 modifications.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
ITC supports the comments submitted by EEI	
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	
Brian Lindsey - Entergy - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
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	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 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	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
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	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	

Document Name	

Comment
BHC will not comment on this requirement.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	
Document Name	

Comment
BHC will not comment on this requirement.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment
Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models. R2: For synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6

Answer	
Document Name	
Comment	
Austin Energy supports LPPC comments. Austin Energy. Segments 1,3,4,5,6	
Likes 0	
Dislikes 0	
Response	

4. Do you agree 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.

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Large System Disturbance Definition: NVE suggests, the SDT better define what is a large system disturbance. NVE suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6 and adding an equivalent voltage criteria. See the technical rationale, section R4 where it's stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation). NVE suggests adding technical rationale language clarifying that large signal performance validation or verification could be completed via simulations. Requirement R4 4.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems. R5 5.3: Same as comments for R2 2.3.	
Likes 0	
Dislikes 0	
Response	

Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The SDT should consider revising this to limit the relay modeling scope to only those relays that are appropriate for the positive sequence modelling and not limiters or protection settings. An additional concern is different expectations of different TPs and how that is communicated to the GOs.	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Regarding R4.2, 4.4, 5.2, and 5.4, the addition of limiters and protection into models is repeating the purpose of PRC-019 and PRC-024. It would be better to come up with another specific requirement for the TP to use this existing information.	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Requirements R4 and R5 are almost identical. It is recommended they be grouped into one requirement.	
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	
Requirements R4 4.1 and R5 5.1: Should not require software/firmware version of IBR and PPC. This information is not typically easily obtainable and is not critical to validating dynamic response of equipment. This detail has not been shown to be critical in the successful modeling of digital excitation systems used for synchronous generator automatic voltage regulation or for digitally based turbine control systems and frequency regulation control systems. Requirement R4 4.3 and R5 5.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating the dynamic behavior of control systems.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE recommends that the minimum dynamics modeling requirements (including any necessary minimum modeling requirements for enabled protections and limiters) be specified in MOD-032 Attachment 1. The TP or PC can request other necessary modeling information as needed, but it is useful for Registered Entities and Compliance Enforcement Authorities if MOD-032 Attachment 1 provides a one-stop shop for the ERO-wide minimum modeling requirements.	

Likes 0	
Dislikes 0	

Response

Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC

Answer	No
Document Name	

Comment

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

R4: For inverter-based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in Section 4.2.5.2, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models.

R4: For inverter-based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in Section 4.2.5.2, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with 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 GWG:

R4.1 and R5.1: software/firmare may be updated multiple times throughout the year. Clarify that it only needs to be verified when that upgrade affects performance

R4.3 and R5.3: is is covered by PRC-019 and should be removed

Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6

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.

R4: Unclear which devices are the responsibility of the GO and which devices are the responsibility of the TO. IBRs – GO; FACTS & HVDC - TO; R5 IBRs – GO, HVDC – TO (need clarification that this is correct and suggesting the above)

Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Suggest the following actions: 1. Create a separate standard for IBRs. 2. Remove requirement to provide software/firmware version numbers to transmission planners. 3. Remove the requirement to supply protection models. 4. Make PRC-019 and PRC-024 documents available to TPs so they can populate models as needed.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA uses standard HVDC models available in grid simulation packages like Siemens PSS/E, GE PSLF or PowerWorld. Model data must match model structure that is currently implemented in the industry used grid simulators. BPA believes that industry would need time to update, modify, or create software in order to meet the intention of IBR modeling.	
Likes 0	
Dislikes 0	
Response	

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

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

Large System Disturbance Definition:

The MRO NSRF suggests, the SDT better define what is a large system disturbance. The MRO NSRF suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6 and adding an equivalent voltage criteria. See the technical rationale, section R4 where it's stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation).

The MRO suggests adding technical rationale language clarifying that large signal performance validation or verification could be completed via simulations.

Requirement R4 4.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.

R5 5.3: Same as comments for R2 2.3.

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 MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
R4 and R5 sub requirements only mention IBR and not the other applicable generation facilities listed in the main requirements.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

Large System Disturbance Definition:

The MRO NSRF suggests, the SDT better define what is a large system disturbance. The MRO NSRF suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6 and adding an equivalent voltage criteria. See the technical rationale, section R4 where it's stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation).

The MRO suggests adding technical rationale language clarifying that large signal performance validation or verification could be completed via simulations.

Requirement R4 4.3: Should not require models to contain limiters and protection settings. This information is already provided in PRC-019 and PRC-024 and is not necessary for validating dynamic behavior of control systems.

R5 5.3: Same as comments for R2 2.3.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro does not agree with including a minimum modeling requirement. We think that it is up to the TP/PC to determine the required minimum modeling requirements and level of the modeling details as stated in R1 (1.1). If the TP/PC determines that some or all these listed minimum requirements are needed to include in the model base or the type of performed studies they can include these as part of the R1 (1.1, level of detail).

Likes 0	
Dislikes 0	

Response

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

As proposed, R4 and R5, each contains a list of information that verified models and accompanying information “shall include at a minimum.” Consider revising that statement to read as follows: “*As applicable*, the verified model(s) and accompanying information shall include, but are not limited to, the following . . . .” This revision would address those instances in which such modeling parameters do not exist. For example, proposed R4.2., R4.3., R5.2. and R5.3. require information related to protection elements. The model components should only be required to include that information if the corresponding device or protection elements exist in the field.

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	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

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

Document Name	
Comment	
PG&E supports the modification to Requirements R4 and R5.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
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 Requirements R4 and R5 modifications.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kristine Howie on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

FirstEnergy supports the proposed language in R4 and R5.

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

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

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

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
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	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 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	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 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	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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	
Brian Lindsey - Entergy - 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	
Document Name	
Comment	
Recommend the following language modification to clarify that asset owners (not interconnecting TOs) are responsible to provide the verified models. R4: For inverter-based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in Section 4.2.5.2, *the asset owner (Generator Owner or Transmission Owner)* shall provide a verified positive sequence dynamic model(s), with associated parameters, and accompanying information that represents the in-service equipment of the Facility to its Transmission Planner, in accordance with MOD-026-2 Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE continues to request the drafting team define the term IBR unit(s) in the NERC Glossary of terms rather than describing it in a footnote of a single requirement (Requirement Part 4.1). It seems as though this term could be used in additional future requirements and it would be more clear to have a NERC Glossary definition.	
Likes 0	

Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
RF recommends minimum dynamics modeling requirements (including any necessary minimum modeling requirements for enabled protections and limiters) be specified in MOD-032 Attachment 1. The TP or PC can request other necessary modeling information as needed, but it is useful for Registered Entities and Compliance Enforcement Authorities if MOD-032 Attachment 1 provides a one-stop shop for the ERO-wide minimum modeling requirements.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree 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.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

We would like clarification on the term “the structure of IBR unit model(s)…” and provide an example of an IBR unit model “structure.”

Based on the existing generation interconnection process in ERCOT, we recommend changing “Transmission Planner” to “Transmission Planner or Planning Authority” in proposed R6. In ERCOT as well as other regions, there are instances in which the Transmission Owner and the Transmission Planner are the same entity. The spirit of the proposed requirement suggests a collaboration of checks and balances to verify modeling accuracy. Requiring a Transmission Owner to send modeling information to itself would not achieve the intended verification of modeling accuracy. Therefore, we advise adding “Planning Authority” in conjunction with “Transmission Planner” for all instances in R6.

Regarding proposed R6.2. and R6.4., attempting to validate a recorded field response against the EMT model will require building an area EMT case. ERCOT does not develop or maintain an official PSCAD case for its Transmission Planners. Building EMT cases for small individual areas would be a substantial undertaking. Instead, it would be more efficient and cost effective for Transmission Planners to validate the EMT models with a simpler, controllable infinite bus test rather than validating them through a full EMT case. Thus, we suggest revising proposed R6.2 and 6.4 to allow Transmission Planners within ERCOT to use this alternative method to validate the EMT models.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

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 long time to train personnel and develop EMT models.

In R6.2, it is not clear what is expected from large signal disturbance responses. It is only defined in the “Technical Rationale” document and more over it is not a NERC defined term in the NERC Glossary of Terms. SDT should consider defining what is meant by a large system disturbance within the standard.

For R6.2, the GO/TO has to provide device test results, which could be hardware in the loop (HIL) tests that are compared against EMT model simulation results. It is unclear whether a detailed network model must be used or a single machine infinite bus model. If the initial HIL tests were closely coordinated with the TP/PC (i.e., via FAC-002), there could be an acceptable network model that was used to confirm performance of models.

"FACTS devices per Section 4.2.4.2" should be changed to "FACTS devices identified in Section 4.2.4.2" to be consistent with the other language used in R6.

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

As mentioned in MRO NSRF's response to question 1, we propose the SDT reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Coordinator and Transmission Planners, as EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint. To accomplish this, we propose the following modification to R6.

R6. For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

The MRO NSRF has concerns about the implementation of required EMT models. While the MRO NSRF understands there is a need, it recommends a 5-year implementation process due to the human, data, training, and computer resources.

• EMT models are complex and it will take 5-years to train personnel and develop EMT models.

• There are a limited amount of consultants available to develop EMT models. A 2-year implementation process will cause a bottleneck on available resources.

• EMT models require data that positive sequence dynamics models don't. Additional new data on new systems must be gathered first to then model. This will take time.

• Entities will need time to identify and purchase new software for EMT models.

• An EMT simulation for something like a NERC Odessa event will require a lot of computer power.

• Industry will need time to develop model conversion software, something like CAPE to EMT model conversions to ease the labor issue, speed model development and keep model accuracy to acceptable levels.

• Verifying EMT models in R6 and R6.1 – R6.4

o For R6.1 and concerns that Original Equipment Manufacturers (OEMs) aren't NERC entities.

o The MRO NSRF suggests replacing the OEM attestation concept with specifications that can be placed in OEM contracts as a superior alternative, "R6.1 Model(s) shall have all inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at generation resource."

o For R6.2 The SDT needs to better define what is a large system disturbance. Small signal disturbances are tested and verified by injecting a small step change into excitation and frequency response controls. An example would be a 2.5% step change. A large disturbance potentially means something that would be outside of a control system or units deadband. Entities should not be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test.

o R6.2 and R6.3, the increased emphasis on EMT validation and large signal testing will drive the inclusion of additional generator models such as:

 Over Excitation Limiters and protection trips

 Under Excitation Limiters and protection trips

 Other protective models

o R6.4, will require a lot of new high speed digital fault recorder technology probably at both the generator low side and high side busses. There are lots of current, voltage, and control signals to monitor to verify something as complex as an EMT model.

o It's the MRO NSRF's understanding that EMT models are computer CPU intensive and only a very limited set of runs are possible. As an example, it's believed that one 5 second run can take several hours.

The MRO NSRF believe the verification and validation definitions need clarification. Specifically, the SDT needs to state clearly in the requirements that large signal verification or validations could be completed using simulations.

The use of verification as defined in the footnotes leaves open the high probability of a never-ending open loop activity of model production for IBR sites that do not react identically to varying disturbance signals.   Each system disturbance is likely to "look" different to the IBR equipment.   Requiring a model that is 100% accurate for all types of system disturbances is not equitable to the stakeholders taxed with the obligation to do so. The equipment owner will never finish developing a model that is guaranteed to predict IBR controls with 100% certainty. A continual remodeling effort will never end.

Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	

The R6 sub requirements only mention IBR not the other applicable generating facilities listed in the main requirement. Also, recommend requirement R6 address the confidentially of the EMT models.

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 both the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	
Response	

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	
Comment	

As mentioned in MRO NSRF's response to question 1, we propose the SDT reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Coordinator and Transmission Planners, as EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint. To accomplish this, we propose the following modification to R6.

R6. For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

The MRO NSRF has concerns about the implementation of required EMT models. While the MRO NSRF understands there is a need, it recommends a 5-year implementation process due to the human, data, training, and computer resources.

{C}· EMT models are complex and it will take 5-years to train personnel and develop EMT models.

{C}· There are a limited amount of consultants available to develop EMT models. A 2-year implementation process will cause a bottleneck on available resources.

{C}· EMT models require data that positive sequence dynamics models don't. Additional new data on new systems must be gathered first to then model. This will take time.

{C}· Entities will need time to identify and purchase new software for EMT models.

{C}· An EMT simulation for something like a NERC Odessa event will require a lot of computer power.

{C}· Industry will need time to develop model conversion software, something like CAPE to EMT model conversions to ease the labor issue, speed model development and keep model accuracy to acceptable levels.

{C}· Verifying EMT models in R6 and R6.1 – R6.4

{C}o For R6.1 and concerns that Original Equipment Manufacturers (OEMs) aren't NERC entities.

{C}o The MRO NSRF suggests replacing the OEM attestation concept with specifications that can be placed in OEM contracts as a superior alternative, “R6.1 Model(s) shall have all inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at generation resource.”

For R6.2 The SDT needs to better define what is a large system disturbance. Small signal disturbances are tested and verified by injecting a small step change into excitation and frequency response controls. An example would be a 2.5% step change. A large disturbance potentially means something that would be outside of a control system or units deadband. Entities should not be required to inject

{C}o large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test.

{C}o R6.2 and R6.3, the increased emphasis on EMT validation and large signal testing will drive the inclusion of additional generator models such as:

{C}§ {C}Over Excitation Limiters and protection trips

{C}§ {C}Under Excitation Limiters and protection trips

{C}§ {C}Other protective models

{C}o R6.4, will require a lot of new high speed digital fault recorder technology probably at both the generator low side and high side busses. There are lots of current, voltage, and control signals to monitor to verify something as complex as an EMT model.

{C}o It’s the MRO NSRF’s understanding that EMT models are computer CPU intensive and only a very limited set of runs are possible. As an example, it’s believed that one 5 second run can take several hours.

The MRO NSRF believe the verification and validation definitions need clarification. Specifically, the SDT needs to state clearly in the requirements that large signal verification or validations could be completed using simulations.

The use of verification as defined in the footnotes leaves open the high probability of a never-ending open loop activity of model production for IBR sites that do not react identically to varying disturbance signals. Each system disturbance is likely to “look” different to the IBR equipment. Requiring a model that is 100% accurate for all types of system disturbances is not equitable to the stakeholders taxed with the obligation to do so. The equipment owner will never finish developing a model that is guaranteed to predict IBR controls with 100% certainty. A continual remodeling effort will never end.

Likes 0	
Dislikes 0	

Response

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	

Comment

To ensure consistent EMT models are provided and the specific EMT simulation tools are used, IID Planners will required time to be trainned on EMT models and its tools/software. Utilities unfamiliarity on EMT modeling will take time to correct

Likes 0	
Dislikes 0	

Response

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

Comment

FirstEnergy supports EEI's Comments which state:

Comments: EEI suggests the following changes in boldface to Requirement R6, noting that the information in the footnotes should be moved out of the footnotes into the body of the Reliability Standard. Additionally, 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.

R6. For applicable units of inverter based resources (IBRs) per identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per identified in Section 4.2.5.1, and VSC HVDC per identified in 4.2.5.2, **commissioned after the date identified in Attachment 1, Row 11, the responsible** Generator Owner or Transmission Owner shall provide **an OEM** verified EMT model(s), **that includes all OEM supplied** associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with **the periodicity in** MOD-026-2 Attachment 1. The verified model(s)model(s) and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1. **Model(s) that contain inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at the generation resource.**;

6.2. Device test results demonstrating a comparison of the IBR unit's response and the IBR unit's EMT model response for large signal disturbances. If device test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason;

6.2.1 A device test that is hardware specific may include a factory type test, hardware in the loop test, or other manufacture manufacturer test to ensure the EMT model's large signal disturbance response emulates the supplied equipment to the extent possible, noting that even detailed EMT models of IBR plants, invariably have certain necessary approximations and limitations.

6.3. **OEM supplied EMT facility** model and with associated parameters representing the IBR unit(s), collector system, auxiliary devices, power plant controller, main transformer(s), and enabled protections and controls that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant **that conforms to the following**;

6.3.1 Models are to have the protections and controls that act on voltage, frequency, and/or current, or act on quantities derived from voltage, frequency, and/or current, which directly trip the IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant represented in the supplied EMT facility model. (*Examples of protections that should be included are IBR unit DC reverse current, DC bus over- and under-voltage, DC voltage unbalance, DC overcurrent, AC over- and under-voltage protection (instantaneous and RMS), AC overcurrent, over- and under-frequency protection, feeder (equivalent) AC over- and under-voltage, feeder (equivalent) over- and under-frequency, PLL (or equivalent) loss of synchronism, and phase jump tripping*.)

6.3.2 Model shall be non-proprietary to ensure compatibility with a wide range of modeling software.

6.4. Validation of the Facility EMT model response using the recorded response for a dynamic volt or VAR reactive power or voltage event, and for a dynamic active power or frequency event in which the power plant controller's or other Facility active power controller's perceived frequency deviates per Attachment 1, Note 1, resulting from either a staged test or a system disturbance; and

6.4.1 Exclusion: LCC HVDC facilities are excluded from the dynamic voltage or VAR event portion of the requirement.

6.5. Documentation comparing the response of positive sequence dynamic model(s) of Requirement R4 and R5 to the response of Facility EMT model of Requirement R6 for large signal disturbances.

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
The EMT model response validation requirement to compare model response to measured system response described R6 part 6.4 likely requires the use of a TP/PC EMT model for the transmission system in the area around the IBR point of interconnection. If the TP/PC is not currently performing EMT modeling, such a model may not exist. Coordination with Project 2022-04 EMT Modeling may help develop improved EMT model verification requirements.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	

Model data must match model structure that is currently implemented in the industry used grid simulators. BPA believes that industry would need time to update, modify, or create software in order to meet the intention of IBR modeling.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

Transmission planners can't study the entire system with EMT models and these models should only be required if Transmission provides justification for them on a case-by-case basis. Technical Justification should include conditions needed to study (e.g., insulation coordination, switching surge, SSR, TRV, higher-frequency control interactions, series capacitor design studies, etc.). If positive sequence models are properly validated/verified, the system can be accurately studied. Providing EMT models will put a significant financial burden on generator owners with minute benefit to the system.

Suggestions:

1. Revise this section to only be required if technical justification is provided from TP.

2. Remove 6.1 - This requirement requests excessive oversight by transmission and implies GOs are not capable of ensuring models are properly documented and precariously expands audit scope.

The risk of non-compliance outweighs the reliability benefits. Not all facilities use a single supplier for all systems. Requiring attestation from OEM is implying GOs are not capable of supplying the correct data.

3. Remove 6.5 - Comparisons of EMT and Positive Sequence Models may have slight differences and comparing the response becomes a point for TP to dispute.

4. Create a separate standard for IBRs.

Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPCO signed on to ACES comments below:

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 1/1/2020 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 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

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

AZPS does not agree that EMT modeling is necessary for dynamic model verification or that the 2 SARs have provided sufficient justification for why it is needed. Concerns for large-signal disturbance behavior are already being addressed by recommended practices such as 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. Since 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 to 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.

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

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC GWG:

R6 is quite burdensome. Suggest having the Planning Coordinator specify which units/plants/sites need to submit EMT models, rather than all

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Buckeye Power, Inc supports the comments made by ACES Power Marketing.

Likes 0	
Dislikes 0	

Response

Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie

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.

Kristine Howie on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #5.	
Likes 0	
Dislikes 0	
Response	
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	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	

R6 asks for GO or TO to provide an EMTP model to **its** Transmission Planner. In the case of HVDC/VSC a second Transmission Planner might be connected to the other end of the HVDC/VSC and will also need to have access to this EMT model. Furthermore, this Transmission Planner might use a different EMT software requiring a different EMT model from the GO or TO. We believe a note should be added indicating this. -6.3 does not indicate what to do in the case an existing facility's manufacturer is out of business (for instance, in the case an EMTP model was not delivered at commissioning). A generic model (based on the technology used or site tuned) should be allowed for those cases.	
Likes 0	
Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	No
Document Name	
Comment	
R6 asks for GO or TO to provide an EMTP model to **its** Transmission Planner. In the case of HVDC/VSC a second Transmission Planner might be connected to the other end of the HVDC/VSC and will also need to have access to this EMT model. Furthermore, this Transmission Planner might use a different EMT software requiring a different EMT model from the GO or TO. We believe a note should be added indicating this. 6.3 does not indicate what to do in the case an existing facility's manufacturer is out of business (for instance, in the case an EMTP model was not delivered at commissioning). A generic model (based on the technology used or site tuned) should be allowed for those cases.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
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	
PGAE agrees with the comments and updates provided by EEI for Requirement R6 on the relocation of the footnotes and that attestations are unenforceable on OEMs.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
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 supports the comments submitted by EEI ITC has the following additional comments: Similar to the current NERC acceptable models list for dynamics models, there needs to be developed an acceptable models list for EMT models. The provided data should not be OEM proprietary models but rather a standard model library. This should be developed prior to the requirement for models going into effect.	
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 reworded such that TPs can identify and then request an EMT model for facilities that are likely to pose risk. Validated EMT models should not be a requirement for all facilities in the proposed applicability scope. At-best, EMT model requests should be driven by specific, critical need as determined by Transmission Planners and then requested under MOD-032. NERC is proposing an EMT Task Force to better understand EMT models and provide guidance around their use. Should the EMT model requirement precede the development of guidance around model development?

Reasons for limiting the applicability:

- EMT modeling for every BES facility will create an undue burden and expense for GOs, TOs and TPs. With the large number of validations and/or revalidations with these requirements, 90 days may not be sufficient to address all usability assessment comments, additional data/model request, etc.
- R.6.1., R.6.2., GOs don't have means to require either of these two items from vendors. For some of the older facilities models, or generic models created for facilities where vendor does not exist these tests are not available.
- EMT modeling software requires specialized computer hardware for analysis and is expensive.
- EMT software analysis requires a unique set of engineering skills and requires much training.
- There is no evidence from TPs that every facility has a need for an EMT model. R.6.4 the necessity of EMT model validation should be mutually agreed and discussed in detail with the corresponding TP, and not mandated by the standard.
- R.6.5. Model benchmarking will place an unnecessary burden on GOs, as positive sequence and EMT modeling is used for different purposes. The amount of details for EMT would depend upon the type of studies intended by TP.
- 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.   Factory type testing, while attempting to emulate the response of the equipment to large system disturbances, invariably have certain necessary approximations and limitations and are unlikely to sufficiently represent all types of disturbances which will occur on the system.   This fact is likely to put owners of IBR resources and TPs in a never ending re-model loop should the model fail to accurately predict the response of the equipment to a disturbance not previously considered.
- 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.

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	

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 1/1/2020 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 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

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

Answer	No
Document Name	

Comment

EMT model requirement seems to be based on one event and not justified in the technical criteria how it would improve the issues identified in the Odessa Report and the WECC reports. This would not constitute an issue that is continent wide. Maybe a region-specific requirement as the issue seems to be in the WECC region. Also, the models that are available for EMT do not seem to add any more value compared to the positive sequence models.

Likes 0	
Dislikes 0	
Response	
Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The SDT should differentiate between sites commissioned before 2020 and have not been updated versus newly commissioned wind farms and windfarms that have been upgraded since 2020.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NVE propose the SDT reduce the barriers and increase the ease of obtaining EMT models for applicable functional entities; e.g. Planning Coordinator and Transmission Planners, as EMT models tend to be manufacturer specific and guarded by manufacturers from a confidentiality standpoint. To accomplish this, we propose the following modification to R6. **R6.** For applicable units of inverter based resources (IBRs) per Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per Section 4.2.5.1, and VSC HVDC per 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s), associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with the periodicity in MOD-026-2 Attachment 1. The verified model(s)and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] NVE has concerns about the implementation of required EMT models. While NVE understands there is a need, it recommends a 5-year implementation process due to the human, data, training, and computer resources. EMT models are complex and it will take 5-years to train personnel and develop EMT models. There are a limited amount of consultants available to develop EMT models. A 2-year implementation process will cause a bottleneck on available resources. EMT models require data that positive sequence dynamics models don't. Additional new data on new systems must be gathered first to then model. This will take time.	

Entities will need time to identify and purchase new software for EMT models.

An EMT simulation for something like a NERC Odessa event will require a lot of computer power.

Industry will need time to develop model conversion software, something like CAPE to EMT model conversions to ease the labor issue, speed model development and keep model accuracy to acceptable levels.

Verifying EMT models in R6 and R6.1 – R6.4

For R6.1 and concerns that Original Equipment Manufacturers (OEMs) aren't NERC entities.

The MRO NSRF suggests replacing the OEM attestation concept with specifications that can be placed in OEM contracts as a superior alternative, "R6.1 Model(s) shall have all inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at generation resource."

For R6.2 The SDT needs to better define what is a large system disturbance. Small signal disturbances are tested and verified by injecting a small step change into excitation and frequency response controls. An example would be a 2.5% step change. A large disturbance potentially means something that would be outside of a control system or units deadband. Entities should not be required to inject large signal disturbances which could damage equipment or cause a system disturbance for a mandatory test.

R6.2 and R6.3, the increased emphasis on EMT validation and large signal testing will drive the inclusion of additional generator models such as:

Over Excitation Limiters and protection trips

Under Excitation Limiters and protection trips

Other protective models

R6.4, will require a lot of new high speed digital fault recorder technology probably at both the generator low side and high side busses. There are lots of current, voltage, and control signals to monitor to verify something as complex as an EMT model.

It's NVE's understanding that EMT models are computer CPU intensive and only a very limited set of runs are possible. As an example, it's believed that one 5 second run can take several hours.

NVE believes the verification and validation definitions need clarification. Specifically, the SDT needs to state clearly in the requirements that large signal verification or validations could be completed using simulations.

The use of verification as defined in the footnotes leaves open the high probability of a never-ending open loop activity of model production for IBR sites that do not react identically to varying disturbance signals. Each system disturbance is likely to "look" different to the IBR equipment. Requiring a model that is 100% accurate for all types of system disturbances is not equitable to the stakeholders taxed with the obligation to do so. The equipment owner will never finish developing a model that is guaranteed to predict IBR controls with 100% certainty. A continual remodeling effort will never end.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Same as No. 2 above	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Same comments as in question 2 above.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	

Comment	
The NAGF supports the proposed Requirement R6 modifications.	
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	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
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	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
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	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
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	
Sheila Suurmeier - Black Hills Corporation - 5	

Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	

Comment	
BHC will not comment on this requirement.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends Footnote 13 be consistent with the description of Facility in section A 4.2.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
-R6 asks for GO or TO to provide an EMTP model to **its** Transmission Planner. In the case of HVDC/VSC a second Transmission Planner might be connected to the other end of the HVDC/VSC and will also need to have access to this EMT model. Furthermore, this Transmission Planner might use a different EMT software requiring a different EMT model from the GO or TO. We believe a note should be added indicating this. -6.3 does not indicate what to do in the case an existing facility's manufacturer is out of business (for instance, in the case an EMTP model was not delivered at commissioning). A generic model (based on the technology used or site tuned) should be allowed for those cases.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree 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.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NVE recommends that NERC MOD-026-1 Requirement R4, Footnote 5 be added back into the Standard as provided clarification to the phrase 'alter equipment response characteristics'.

NVE has concerns with the "large" signal disturbances. NVE suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6.

Reference: See the technical rationale, section R4 where it's stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation) and large signal performance via documentation and analysis exercises.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The timeframes are not aligned between R8 and M8. R8 states 120 calendar days while M8 states 90 calendar days. As this was a change from the previous draft, it is assumed that M8 was simply overlooked. R9 references MOD-026-2 Attachment 1; however, there is no corresponding section in Attachment 1. We recommend one of the following actions:
1. Remove the reference to Attachment 1 from R9.
2. A section specific to the notification of denial timeline be added to the periodicity table in Attachment 1
OR
3. Add additional clarification to R9 indicating how the periodicity table in Attachment 1 is applicable to R9.

Given that R9 already contains a timeline of 90 calendar days within the Requirement, our preferred course of action is item 1 above.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	
In R7, updated models may be provided after making a hardware, software, firmware, control mode, or setting changes, this should be changed to 90 days prior to making the changes so that they may be evaluated prior to the facility being returned to service. MOD-026-2 R8, says TP shall provide the written response within 120 days. While in M8, it says TP must provide dated evidence with 90 days. Is this a kind of conflict? M8 should have been changed. Should R9 also be 120 days?	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
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 to be the intent of R9. **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	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	

Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

Requirement R7 is a little ambiguous in how it is worded. It could be changed to be similar to R9. Recommend changing the wording of R7 to:

Each Generator Owner or Transmission Owner upon making a hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that alters the equipment response characteristic, in accordance with MOD-026-2 Attachment 1 shall, within 180 days, provide to its Transmission Planner:

•   An updated verified model and accompanying information in accordance with Requirements R2–R6, or

•   A plan to verify the model in accordance with Requirements R2–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	

Southern Company recommends replacement of “Transmission Planner” with “Transmission Planner and/or Planning Coordinator” in Requirements R7., R8., and R9.

We have concerns with the “large” signal disturbances. We suggest defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6.

Reference: See the technical rationale, section R4 where it’s stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation) and large signal performance via documentation and analysis exercises.

The model verification periodicity information contained in Requirement R7 should be removed in favor of the information already provided in Attachment 1. Duplicative periodicity information in this requirement adds unnecessary confusion for entities with obligations.	
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 supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	
Portland General Electric Company supports the comments submitted by the Edison Electric Institute.	
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	
PGAE agrees with the comments provided by EEI for:	

1 - Question 6 on the model verification periodicity information contained in Requirements R7, R8, and R9 should be removed in favor of the information provided in Attachment 1. The duplicative periodicity information in the Requirement and Attachment adds unnecessary confusion to an entity's obligations.

2 - The input on Footnote 5 from MOD-026-1 Requirement R4 on reconsideration of the deletion or adding similar clarifying language to the next draft.

3 – The input on Requirement R9 needs to include a dispute resolution process.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No

Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	No
Document Name	
Comment	
At M8, the delay should be 120 calendar days, to be consistent with R8.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

Recommend that 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 do in fact 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 the mechanical hydraulic to electo-hydraulic governors or making a similar change in control type.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

In MOD-026-2 R8, it says TP shall provide the written response within 120 days. While in M8, it says TP must provide dated evidence with 90 days. Is this a typo error?

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #6.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

On behalf of the SERC GWG:

R7 is a little ambiguous in how it is worded. It could be changed similar to R9:

Each Generator Owner or Transmission Owner upon making a hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that alters the equipment response characteristic, in accordance with MOD-026-2 Attachment 1 shall, within 180 days, provide to its Transmission Planner:

- An updated verified model and accompanying information in accordance with Requirements R2–R6, or
- A plan to verify the model in accordance with Requirements R2–R6.

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	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

For Requirement 7, AZPS recommends that the following bolded edit be added:

R7. Each Generator Owner or Transmission Owner shall provide an updated verified model(s), or a plan to verify the model(s), in accordance with one or more of Requirements R1, R3, R4, R5, of R6 to its Transmission Planner within 180 calendar days of making a **functional change** to hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that **results in a different response of the unit or would impact an interconnected transmission line** alters the equipment response characteristic, in accordance with MOD-026 Attachment 1.

For Requirements 7 and 9, AZPS does not agree with removing the phase "mutually agreed upon" as we believe any that the GO and the TO should agree on plans for model verification.

Likes 0	
Dislikes 0	
Response	

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

AEPCO signed on to ACES comments below:

The timeframes are not aligned between R8 and M8. R8 states 120 calendar days while M8 states 90 calendar days. As this was a change from the previous draft, it is assumed that M8 was simply overlooked.
R9 references MOD-026-2 Attachment 1; however, there is no corresponding section in Attachment 1. We recommend one of the following actions:
1. Remove the reference to Attachment 1 from R9.
2. A section specific to the notification of denial timeline be added to the periodicity table in Attachment 1
OR
3. Add additional clarification to R9 indicating how the periodicity table in Attachment 1 is applicable to R9.
Given that R9 already contains a timeline of 90 calendar days within the Requirement, our preferred course of action is item 1 above.

Likes 0	
Dislikes 0	

Response	
Josh Combs - Black Hills Corporation - 3	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

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

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The 90-day timeline in Requirement R8 has been revised to 120 calendar days. However, the corresponding Measure M8 has not been revised accordingly. Please correct this apparent oversight. The rationale for increasing the TP timeline in R8 was reported as the additional scope of reviewing the EMT models. The same rationale would also apply to the GO/TO that need to accommodate the additional scope of developing these EMT models and/or the associated verification plans. For consistency, BC Hydro supports increasing the R9 timeline for the GO/TO in R9 from 90 to 120 days, consistent with the revised R8 timeline for the TP.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
1 R1 is open ended - Specifics to comply should be detailed in this standard as in the existing MOD-026 and MOD-027 standards. 2. M8 - Remove the need to supply review date of submitted model and accompanying information. Response within the 90 days is sufficient. 3. R7 - Provide clarity on how the 180-day requirement applies. Existing language could be read that it only applies to the agreed upon plan, and not to the updated model.	

4. M8 - Revision error: Change 90 calendar days to revised 120 calendar days.	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF recommends adding a statement to the “Technical justification and supporting evidence for maintaining the current model” option in R9 stipulating that the technical justification cannot be used to justify retaining a model, format, or level of detail that is not acceptable to the TP/PC. As currently written, GO/TOs may attempt to use the R9 “technical justification” option to maintain models that are not acceptable to the TP/PC under R1 Part 1.1 or Part 1.2.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

We recommend adding that the Transmission Planner’s request for a model review in R9 may also be justified on the basis of the simulated unit or plant response not matching the measured unit or plant response to an event as in the existing MOD-026 R3, R5 footnote 6 and MOD-027 R3. Also, please note that the language shown in the mapping document on page 6 for R9 differs from that in the proposed standard R9 text and we prefer the language as provided in the mapping document (“…or a technical justification for model review…”) which suggests a model review may be initiated for reasons not limited to “identified model or accompanying information deficiencies.”

R9 in draft standard:
“R9. Each Generator Owner or Transmission Owner 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* shall provide a written response to its Transmission Planner within 90 calendar days of receiving a notification or request, *in accordance with the periodicity in MOD-026-2 Attachment 1*. The written response shall contain one of the following:”

R9 on page 6 of Mapping Document:
“R9. Each Generator Owner or Transmission Owner receiving a notification of denial under Requirement R8 or a *technical justification for model review* shall provide a written response to its Transmission Planner within 90 calendar days of receiving a notification. The written response shall contain one of the following:”

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's Comments which state: The model verification periodicity information contained in Requirements R7, R8 and R9 should be removed in favor of the information provided in Attachment 1. Duplicative periodicity information in these requirement adds unnecessary confusion as to entity obligations. For example: Requirement R7 states updated verified model(s) or a plan to verify the model per R2, R3, R4, R5 or R6 is to be submitted to the TP within 180 calendar days, while Attachment 1, Row 5 states 180 days is required unless a plan is submitted, then 365 days after submission of a plan is allowed. To avoid this conflict, all model verification periodicity should only be in attachment 1. **Deletion of Footnote 5, MOD-026-1, Requirement 4** (*R4 has been mapped to R7*): EEI is concerned that the deletion of footnote #5 from the MOD-026-1 (i.e., not included in the current draft) has created an area of possible compliance ambiguity and risk for responsible entities. This footnote was previously included in MOD-026-1, R4 to provide clarity over what kind of changes "that alter the equipment response characteristics" are in scope. Moreover, the deletion of this footnote leaves auditors and responsible without clear direction as to the intended scope. For this reason, we ask the SDT to reconsider the deletion of footnote 5 (from MOD-026-1) or to add similarly clarifying language to the next draft. EEI additionally Requirement R9 needs to include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.	
Likes 0	
Dislikes 0	
Response	

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
The SDT did not address the structural concerns identified by the MRO NSRF Draft 1. The MRO NSRF recommends that NERC MOD-026-1 Requirement R4, Footnote 5 be added back into the Standard as provided clarification to the phrase 'alter equipment response characteristics'. The MRO NSRF has concerns with the "large" signal disturbances. The MRO NSRF suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6. **Reference:** See the technical rationale, section R4 where it's stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation) and large signal performance via documentation and analysis exercises.	
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 both the MRO NSRF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

The MRO NSRF recommends that NERC MOD-026-1 Requirement R4, Footnote 5 be added back into the Standard as provided clarification to the phrase ‘alter equipment response characteristics’.

The MRO NSRF has concerns with the “large” signal disturbances. The MRO NSRF suggests defining large system disturbance by moving Attachment 1, Note 1 to the top in Section 6.

Reference: See the technical rationale, section R4 where it’s stated R4 is specific to positive sequence modeling and reflects the intent of the SAR to verify both small signal performance via staged testing (termed as validation) and large signal performance via documentation and analysis exercises.

Likes 1	Lincoln Electric System, 1, Johnson Josh
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 electo-hydraulic governors or making a similar change in control **type**.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	No
Document Name	

Comment

Requirement 7 does not provide a specific threshold of how much of a change would require a new model. In reality, moving from a mechanical hydraulic governor to an electric hydraulic governor, changing the droop, or changing the deadband are the only major alterations.

Attachment 1, Row 5 is a circular reference back to R7 and does not provide clarity. This should be corrected.

Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Based on the existing generation interconnection process in ERCOT, we recommend changing “Transmission Planner” to “Transmission Planner or Planning Authority” in proposed R7. In ERCOT as well as other regions, there are instances in which the Transmission Owner and the Transmission Planner are the same entity. The spirit of the proposed requirement suggests a collaboration of checks and balances to verify modeling accuracy. Requiring a Transmission Owner to send modeling information to itself would not achieve the intended verification of modeling accuracy. Therefore, we advise adding “Planning Authority” in conjunction with “Transmission Planner” for all instances in R7.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
At M8, the delay should be 120 calendar days, to be consistent with R8.	
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	
Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
Answer	Yes
Document Name	
Comment	

Constellation agrees with proposed language.

Kristine Howie on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

SIGE would request that the word “material” be changed to “model data and accompanying information” under R8.

For R9, under the second bullet, the generators are able to provide the revised models to the Transmission Planner and technical justification and supporting evidence for maintaining the current model, 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	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	Yes
Document Name	

Comment	
PNM Resourced agrees with the R7, R8, and R9 language, however measure M8 does not reflect the time requirement change from 90 days to 120 days as defined in the associated requirement R8.	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Please see CHPD comment further in this document regarding the term 'Change' in R7, Attachment 1, row 6. This ought to be further clarified either in the standard, supporting rationale, or other documentation from NERC.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
The time- period for the written response to the submitter in M8 should be changed to 120 days to match with R8.	
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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
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	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
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	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. The 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.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
ERCOT does not develop or maintain an official PSCAD case for its Transmission Planners. Building EMT cases for small individual areas would be a substantial undertaking. Instead, it would be more efficient and cost effective for Transmission Planners to validate the EMT models with a simpler, controllable infinite bus test rather than validating them through a full EMT case.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Development of EMT models requires trained individuals and time. Therefore, SDT should consider the comments provided in Q1. Some of the detail protection and control elements described in the standard as the minimum requirements may not be useful in positive sequence simulation models. This type of requirements will force entities to allocate time and resources to develop user defined models which may not be that useful at the end, but rather make the models more complicated and difficult to maintain with software version changes. Such detailed protection and control models may be needed only for EMT models. 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	

Brian Lindsey - Entergy - 1	
Answer	No
Document Name	

Comment	
Do not have enough information to determine what the cost impacts will be.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
See our comment below regarding units with one-way governor response.	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

The MRO NSRF is in agreement from a Generator Owner standpoint, so long as the implementation plan maintains the following statement, “Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 within the periodic timeframes of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2).”

The MRO NSRF cannot comment on the cost effectiveness of developing an EMT model, please see response to question 8, as its members and guest have little to no experience with EMT model development.

Likes 1	Lincoln Electric System, 1, Johnson Josh
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 MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

We encourage the SDT to coordinate model requirements and processes with other efforts, such as electromagnetic transient (EMT) modeling and validation that are being contemplated for other standards. Duplication of requirements across standards can lead to inefficiencies, the need to subsequently modify (or combine) standards, and, if the requirements are not identical, conflicts and confusion.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	No
Document Name	
Comment	

The SDT did not address the structural concerns identified by the MRO NSRF Draft 1.

The MRO NSRF is in agreement from a Generator Owner standpoint, so long as the implementation plan maintains the following statement, “Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 within the periodic timeframes of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2).”

The MRO NSRF cannot comment on the cost effectiveness of developing an EMT model, please see response to question 8, as its members and guest have little to no experience with EMT model development.

Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	
Comment	

IID supports LPPC position that most of the registered entities (including IID) don’t have the skill, experience or software to work with EMT models required by MOD-026-2. Utilities unfamiliarity on EMT modeling will take time to fix.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

Initial Cost Effectiveness cannot be determined at this time.

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
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.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
The modifications do address the issues in the 2 SARs. RF notes that additional EMT model verification items are included that relate to the recently initiated Project 2022-04 EMT Modeling. The EMT project may be able to address the EMT model verification items, allowing this project moving forward.	

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA believes the revisions are not cost effective. This version of the standard puts a substantial burden on the industry to find contractors to do a complete overhaul of testing. The proposed standard does not account for the current 10-year testing life cycle of the existing standards. There is very limited expertise available for EMT models on the Generator Owner and Transmission Planner sides, which also creates a burden by attempting to utilize the same resources.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Properly populated generic positive sequence models for IBRs can accurately represent the equipment sufficiently for studies. The cases mentioned in the SAR were a result of improper equipment settings not a modeling issue. Requiring EMT models and simulations will add significant costs to GOs when the focus should be on properly verifying existing ones.

While EMT and positive sequence models are useful for their specific studies (e.g., EMT is mainly used for insulation coordination, switching surge, SSR, TRV, higher-frequency control interactions, series capacitor design studies, etc.), when comparing the models, one must be aware of the differences of the two domains and the limitations of such comparisons.

Transmission planners can't study the entire system with EMT models and should only be required if Transmission provides technical justification for them on a case-by-case basis.

The requirement to provide protection models will add significant time and dollars to submittals with little benefit to reliability studies. This will require most Generator Owners to maintain licensed copies of PSSe/PSLF as well.

Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPCO signed on to ACES comments below: The attestation proposed in R6.1 could become overly costly and, in our opinion, does not provide a good return on investment as currently written. See response to question 5 above for additional details.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
As outlined above in AZPS's response to Questions, 2, 3, 4, and 5 above, AZPS believes that many of the SDT's recommendations are already being addressed by other standards or will require significant additional work with minimal benefit to reliability.	
Likes 0	

Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	
Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie	
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. Kristine Howie on behalf of Constellation Segments 5 and 6	
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	
Many entities currently do not possess the software to perform/validate or have the personel trained to perform EMT studies. It will take a large outlay to train people appropriately and acquire the necessary hardware and software to perform EMT studies. We estimate it will be Q2 of 2025 before we can budget for and purchase the required software and then train people adequately to perform EMT model studies. We would ask that the	

implementation date be pushed back for the base requirements until after that time so entities will be able to purchase the software, train their employees and develop modeling requirements prior to the enforcement date.

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

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

For traditional synchronous generating resources, this revision adds new requirements not previously modeled (e.g., excitation limiters and protection systems) and modifies the Applicability section to include generating facilities not previously applicable. This is a significant cost and modeling effort for synchronous generator owners. The scope of the SARs was primarily to revise MOD-026 and MOD-027 to address Transmission connected dynamic resources and IBRs. The additional R2.2 and R3.3, and changes to the Applicability section, are not directly captured in the SARs.

Regarding efficiency, combining MOD-026 and MOD-027 may seem to be more efficient on the surface but in reality, these two Standards are generally performed together and combining the two Standards may not create more efficiencies.

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	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
EMT models are not used by most Transmission Planners and the transmission software tools to study the entire system with EMT models currently do not exist. CEHE believes that the required models' level of detail should be within the simulation tool's modeling capabilities and reasonable industry practices. The EMT models should only be requested/provided based on proper justification and on a case-by-case basis. Most Registered Entities do not have the historical experience or software to work with EMT models required by MOD-026-2. Utilities' unfamiliarity with EMT modeling will take many work hours from engineers or consultants, and other staff to modify all of the compliance processes already established.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
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 cannot fully comment if the modifications are cost effective until the modifications are completed, but does have the following input: The additional model(s) required in Requirements R2 and R3 (example: OEL and enabled Protection System) should only be required if they are required by the Transmission Planner (TP). If they are not utilized by the TP, but still required under R2 and/or R3, the additional burden is not cost effective. The Requirement language should be updated to eliminate steps that will not be required if the TP indicates they are not required.	
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. With limited expertise available for EMT modeling, the cost to contracting entities will definitely be significant – the price of this service is like any other service that follows the supply/demand economic impact. As long as the implementation plan maintains the following statement, “Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 within the periodic timeframes of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2).”, we are in agreement with positive sequence model verification plan.	
Likes 0	
Dislikes 0	

Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI supports comments provided by the NAGF.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Cost impact is not clear. Reference comments to other questions, as the proposed MOD-026-2 does not appear to effectively enhance reliability or completely address the associated SARs.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
The attestation proposed in R6.1 could become overly costly and, in our opinion, does not provide a good return on investment as currently written. See response to question 5 above for additional details.	
Likes 0	
Dislikes 0	
Response	

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

Relative to validation, there is a lack of independent, quantified assessment on the effectiveness and improved reliability of the current versions of the MOD-026-1 and MOD-027-1. 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.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NVE is in agreement from a Generator Owner standpoint, so long as the implementation plan maintains the following statement, “Applicable Entities shall initially comply with the periodic requirements (Requirements R2, R3, R4, and R5) in MOD-026-2 within the periodic timeframes of their last performance under the respective requirement in the Requested Retired Standards (MOD-026-1 R2 or MOD-027-1 R2).”

NVE cannot comment on the cost effectiveness of developing an EMT model, please see response to question 8, as its members and guest have little to no experience with EMT model development.

Likes 0	
Dislikes 0	
Response	

Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

Additional models need to be developed, tested, and validated. There are limited resources available who can provide these services. Manufacturers may not be able to support PSCAD models development for equipment that is no longer supported or in production.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern that the cost effectiveness of this project has not been addressed. As we have reviewed the initial SAR as well as the two SARs in reference to IBRs and Transmission Connected Dynamic Reactive Resources. The concern is that each cost effectiveness section of the SARs has an unknown impact on cost.

From our perspective, the cost of effectiveness of the proposed standard cannot be measured, because the SAR or SDT drafting team hasn't clearly addressed the potential costs of this project.

SPP recommends that the drafting team structure some type of initial cost analysis to help give industry an idea about cost. Again, from our perspective, there's no clear data showing the cost impact of the project which means industry can't evaluate cost if the proposed standard provides no cost data to review.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC

Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
As we commented on Draft 1, the NERC Standard Processes Manual (Version 4, dated March 1, 2019) outlines a process for conducting field tests (Section 6.0) to help a drafting team "analyze data and validate concepts in the development of Reliability Standards". It seems this process is rarely if ever used in developing NERC standards. In the case of the proposed MOD-026- 2, we believe a properly designed fie ld test could help inform the drafting team of any potential issues in implementing the draft requirements and also provide further insights on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes

Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No comment. WECC believes the applicable entities are best suited to respond to this question.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
BHC will not respond to cost effectiveness.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC supports the comments submitted by EEI	
Likes 0	
Dislikes 0	
Response	

8. The SDT proposes a 1-year implementation plan for Requirements R1, R7, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained 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.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern about the implementation of this project. The concern is that there are other projects such as MOD-032, EMT as well as other projects that has an impact on modeling, studies and data collection in reference to IBRs, DERs and ESRs. The drafting team needs to take into consideration the implementation of other projects to make sure that all reliability gaps are addressed.

We recommend that the drafting team coordinate with other NERC drafting teams (ie MOD-032, EMT, etc) to ensure that each effort is seamless. If not, there will be a lot of confusion on expectations, specifically, in the reliability and compliance areas.

Likes 0	
Dislikes 0	

Response

Tony Hua - Austin Energy - 4

Answer	No
Document Name	

Comment

Austin Energy supports LPC comments

Likes 0	
Dislikes 0	

Response

Michael Dieringer - Austin Energy - 3

Answer	No
Document Name	

Comment

Austin Energy supports LPPC comments

Likes 0	
Dislikes 0	

Response

Hannah Lauer - Avangrid Renewables - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

We believe that a 3-year implementation is too aggressive. As stated above, many of our windfarms are older than 10-years. We request a minimum of 6-year implementation for existing sites.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6

Answer	No
Document Name	

Comment

Austin Energy supports LPPC comments.

Austin Energy. Segments 1,3,4,5,6

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 / BANC

Answer	No
Document Name	

Comment	
SMUD and BANC support the comment of LPPC.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NVE has concerns for the 3 year implementation of EMT models. Industry will need time to train personnel, hire consultants and develop EMT models. There are a limited number of consultants and personnel that can develop such models. NVE recommends a 5 year staged implementation.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Requirements R2-R6 should have a five-year implementation.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	

A 24-month implementation period for R1 is recommended.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AECI supports comments provided by the NAGF.

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

There is no way R6 could be completed in 3 years as described. 10 years would be a challenge. 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. We strongly oppose inclusion of R6, but if it is mandated, three years is woefully insufficient to complete for all applicable facilities. A 10-year phase-in period should be considered at minimum. This integration period will permit all parties the flexibility to balance the work load of the current modeling requirements for subsequent model verification along with new work resulting from this revision to MOD-026.

Likes 0	
Dislikes 0	

Response

John McCaffrey - American Public Power Association - 4 - NA - Not Applicable

Answer	No
Document Name	

Comment	
APPA is concerned about how the proposed implementation timeframes for Project 2020-06 may align with the timeline established by the NERC work plan developed in response to FERC’s Registration of Inverter-based Resources (IBR) Order and any obligations arising from FERC’s pending Notice of Proposed Rulemaking (NOPR) proposing to direct NERC to modify or develop reliability standards to address perceived reliability gaps related to IBRs . The proposed MOD-026 changes are a significant effort and cost for entities. Many entities do not have the expertise to perform the work required to comply with MOD-026, and will need to contract with vendors. There are a limited number of vendors available to perform this work, as noted by other commentors. APPA is concerned that the IBR Order and associated IBR NOPR, will necessitate another revision to MOD-026. Back-to-back revisions to MOD-026 will negatively impact entities who already contracted the scope of work. Entities will need to revise or rush to negotiate new contracts for these additional units. In establishing the implementation timeframes for MOD-026, APPA strongly encourages the SDT to take steps to reconcile the timing of compliance obligations with any expanded or modified MOD-026 obligations resulting from the FERC proceedings so as to avoid the risk of duplicative or inefficient workstreams. Ensuring that implementation of MOD-026 aligns with any obligations resulting from the IBR Order and IBR NOPR will be more cost effective and will ultimately save time in implementing the Requirements, since contracts won't need to be modified or work re-performed.	
Likes 0	
Dislikes 0	
Response	
Joseph McClung - JEA - 1, Group Name LPPC	
Answer	No
Document Name	
Comment	
LPPC is concerned about how the proposed implementation timeframes for Project 2020-06 may align with the timeline established by the NERC work plan developed in response to FERC’s Registration of Inverter-based Resources (IBR) Order and any obligations arising from FERC’s pending Notice Of Proposed Rulemaking (NOPR) proposing to direct NERC to modify or develop reliability standards to address perceived reliability gaps related to IBRs. The proposed MOD-026 changes are a significant effort and cost for entities. Many entities do not have the expertise to perform the work required to comply with MOD-026, and will need to contract with vendors. There are a limited number of vendors available to perform this work, as noted by other commentors. LPPC is concerned that the IBR Order and associated IBR NOPR, will necessitate another revision to MOD-026. Back-to-back revisions to MOD-026 will negatively impact entities who already contracted the scope of work. Entities will need to revise or rush to negotiate new contracts for these additional units. In establishing the implementation timeframes for MOD-026, LPPC strongly encourages the SDT to take steps to reconcile the timing of compliance obligations with any expanded or modified MOD-026 obligations resulting from the FERC proceedings so as to avoid the risk of duplicative or inefficient workstreams. Ensuring that implementation of MOD-026 aligns with any obligations resulting from the IBR Order and IBR NOPR will be more cost effective and will ultimately save time in implementing the Requirements, since contracts won't need to be modified or work re-performed.	
Likes 2	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; JEA, 3, Williams Marilyn
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 supports the comments submitted by EEI

ITC has the following additional comments:

For R8, the time frame specified of 120 days seems too short for the model verification especially when it includes an EMT model and could also be based on the parameters identified in the procedure identified by TPs/PC for the verification in R1.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Portland General Electric Company supports the comments submitted by the Edison Electric Institute.

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 indicates for newly applicable synchronous generating facilities (facilities with a lower MVA threshold than previously required), a phased-in implementation that is similar to what was provided in MOD-026-1 and MOD-027-1 be added to the implementation plan. This will allow applicable entities to allocate scarce resources to accommodate the addition of the newly applicable facilities.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	No
Document Name	

Comment

CEHE supports the comments as submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC

Answer	No
Document Name	

Comment

R7 should have an additional 3 years for compliance, like R2-R6. The rationale is that if a hardware, software, firmware, control mode, or setting change to in-service equipment is made after the effective date of MOD-026-02, compliance to requirements R2-R6 (based on this change) should not happen before R2-R6 compliance date.

Also, the version of the “BES definition” that is mentioned at section A.4.2 of MOD-026-02, should be clearly stated in MOD-026-02, to avoid any misunderstanding regarding the applicability criteria. Rationale: If a new version of the “BES definition” with new applicability criteria is released in the future, a new implementation plan will be necessary to allow the implementation of the newly applicable units. This is not covered in the proposed MOD-026-02, and therefore the version of the “BES definition” should be added. If MOD-026-02 is kept as proposed, a change in the applicability criteria of the “BES definition” will cause the newly applicable units to be compliant right away, which is not possible. Another solution would be to add a new item in attachment 1 to cover a “BES definition” applicability criteria change.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

R7 should have an additional 3 years for compliance, like R2-R6. The rationale is that if a hardware, software, firmware, control mode, or setting change to in-service equipment is made after the effective date of MOD-26-02, compliance to requirements R2-R6 (based on this change) should not happen before R2-R6 compliance date.

Likes 0	

Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Additional implementation plan clarification is needed regarding how the proposed MOD-026-2 periodic compliance deadlines work with the current periodic requirements of MOD-026-1 and MOD-027-1. For example, per the current MOD-026-1 and MOD-027-1 a unit has verification dates being 6/1/2015 and 6/1/2022. Assuming a MOD-026-2 effectiveness date of 9/1/2024, are the deadlines of 9/1/2027 for MOD-026-2 R2 excitation system testing (three years from the effectiveness date, but more than ten years from the previous verification) and 6/1/2032 for the R3 governor testing?	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
In general, we found the wording of the Draft 2 Implementation Plan to be confusing. See additional comments on the Implementation Plan under our response to Q9. As we commented on Draft 1, we recommend an additional 4 years for compliance with Requirements R2-R6 for newly applicable Facilities (5 years after the effective date of the applicable governmental authority's order approving the standard).	
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 supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #8.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc supports the comments made by ACES Power Marketing.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	

APPA/LPPC recommends that Project 2020-06 should be delayed to align with the timeline established by the IBR Order work plan. The proposed MOD-026 changes are a significant effort and cost for entities. Many entities do not have the expertise to perform the work required to comply with MOD-026, and will need to contract with vendors. There are a limited number of vendors available to perform this work, as noted by other commentors. APPA/LPPC is concerned that the IBR Order and associated IBR NOPR, will necessitate another revision to MOD-026. Back-to-back revisions to MOD-026 will negatively impact entities who already contracted the scope of work. Entities will need to revise or rush to negotiate new contracts for these additional units. Waiting a few months to ensure MOD-026 aligns with the IBR Order is more cost effective and will ultimately save time in implementing the Requirements, since contracts won't need to be modified or work re-performed.

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

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

AZPS agrees with EEI's comments that "the rapid changes being made to require verified resource EMT models for introduction into area and regional EMT studies is out pacing the industry's ability to comply. This includes OEMs and responsible entities who are both being challenged to provide verified EMT models that are non-proprietary and broadly useful to planners. All of this requires the support of a limited number of qualified consultants and necessitates substantial training to ensure responsible entity staff."

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	

We could comply with the dynamic modeling as proposed within the implementation period, however we could not provide the EMT modeling within the proposed implementation plan. It would be difficult to provide an alternate estimate timeframe for the EMT requirements since we currently do not have any modeling and would require further guidance from NERC.

Likes 0	
Dislikes 0	
Response	

Josh Combs - Black Hills Corporation - 3

Answer	No
Document Name	
Comment	

BHC supports the NAGF comments.

Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1

Answer	No
Document Name	
Comment	

BHC supports the NAGF comments.

Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6

Answer	No

Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
BHC supports the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy suggest a 5-year implementation plan for R2-6 and a 2-year implementation plan for R1, R7, R8, and R9. This period is needed because NERC auditors require GOs to establish program documents, procedures, test plans, work orders, etc. Duke Energy will require time to make these changes and considers the suggested timeframe too restrictive.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
For existing facilities, a 1-year implementation plan does not allow adequate time for the TP/PC to develop dynamic model verification requirements and processes, nor, for software to be developed and available for industry use. If a GO's testing is due within two years, the GO would then also need to include the EMT models. BPA believes finding knowledgeable, trained resources (contractors) to provide viable, accurate models isn't feasible within this timeframe. It will take several years before resources can gain the industry knowledge, skills, and ability to provide EMT Models. This would present bottlenecks for those waiting to have viable, accurate EMT Models completed within compliance timeframes. Ultimately, this would create a rush for Generator Owners, which would then potentially cause the dissemination of unreliable/inaccurate data to Transmission Planners. BPA believes this creates a "cart before the horse" scenario. For newly applicable facilities, BPA believes a feasible timeframe would be created if EMT Models were included as part of the Generation Interconnection process.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF does not object to the implementation plan intent described in question 8. However, the language in the posted implementation plan draft is different. The "Compliance Date for MOD-026-2 – Requirements R2, R3, R4, R5, and R6" section of the implementation plan uses the language "Applicable Entities shall not be required to comply…", which is broader than solely addressing newly applicable Facilities that were not applicable under MOD-026-1 and MOD-027-1. As currently drafted, the implementation plan apparently retires MOD-026-1 and MOD-027-1 thirty-six (36) months prior to when Applicable Entities are required to comply with replacement requirements MOD-026-2 R2, R3, R4, and R5, creating a gap period during which neither the standards to be retired nor the replacement requirements in the new standard are enforceable. While a phased implementation plan over a 3- or 4-year period may be appropriate for newly applicable facilities, an enforceability gap in model verification requirements for already applicable facilities may have a negative impact on transmission planning analysis quality and interconnection queue study timeliness.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No

Document Name	
Comment	
Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's Comments which state: While EEI supports the changes being implemented in MOD-026 by the SDT, the rapid changes being made to require verified resource EMT models for introduction into area and regional EMT studies is out pacing the industry's ability to comply. This includes OEMs and responsible entities who are both being challenged to provide verified EMT models that are non-proprietary and broadly useful to planners. All of this requires the support of a limited number of qualified consultants and necessitates substantial training to ensure responsible entity staff. The SDT should consider a 60 month implementation plan**, specifically 2-years for R1, R7, R8 and R9 and the 3 additional years for Requirement R2-R6,** that would provide responsible entities sufficient time to develop trained staff and allow affected OEMs the ability to develop non-proprietary models that more could accurately reflect the performance of the resources they are suppling to the industry.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID supports LPPC recommendation for the implementation period for R6 be extended from 36 to 48 months to allow Entities enough time to purchase, installed and be trained on EMT software, to develop expertise with EMT modeling and studies. Additional time will be required to ensure that models used by registered entities are compatible with the models used by their regions and different software vendors.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response	
Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Document Name	
Comment	
The MRO NSRF has concerns for the 3 year implementation of EMT models. Industry will need time to train personnel, hire consultants and develop EMT models. There are a limited number of consultants and personnel that can develop such models. The MRO NSRF recommends a 5 year staged implementation.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD engineers do not have experience with EMT modeling and require more time to facilitate training. SNPD proposes a 3-year implementation plan for Requirements R1, R7, R8, and R9, and 5 years for compliance with Requirements R2-R6 for newly applicable Facilities.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
The requirement to develop acceptable electromagnetic transient (EMT) models, format, and level of detail is likely to involve the vetting, purchase, and training of applicable staff in new EMT software. Because of this we recommend a 2-year implementation plan for R1, R7, R8, and R9.	
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 MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM Resources recommends a longer implementation period for requirements R1.2 and R6. Requirement R6 needs a longer implementation period due to the time needed for the GOs to attain these models and requirement R1.2 should also be given a longer implementation period since the Transmission Planners will need time to acquire and learn how to use EMT software. The other requirements should not require additional implementation time.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF has concerns for the 3 year implementation of EMT models. Industry will need time to train personnel, hire consultants and develop EMT models. There are a limited number of consultants and personnel that can develop such models. The MRO NSRF recommends a 5 year staged implementation.	

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

Implementation Plan clarification is needed regarding how the statement that compliance shall not be required until 36 months after the effectiveness date of MOD-026-2 fits with the later input that entities shall initially comply in accordance with the periodic requirements of MOD-026-1 and MOD-027-1. Take for example a unit with the latest MOD-026-1 and MOD-027-1 verification dates being 6/1/2015 and 6/1/2022 respectively, and a hypothetical MOD-026-2 effectiveness date of 9/1/2024. Are the deadlines 9/1/2027 for MOD-026-2 R2 excitation system testing (three years from the effectiveness date, but more than ten years from the previous verification) and 6/1/2032 for the R3 governor testing?

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie

Answer	Yes
Document Name	

Comment

Constellation has no additional comments

Kristine Howie on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	Yes
Document Name	

Comment

On behalf of the SERC GWG:

Under Effective Date: slightly ambiguous the effective dates for existing facilities. Suggest specifically calling out the 10 year reoccuring in that section

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP thanks the Standard Drafting Team for extending the Implementation Period, as we suggested in the previous comment period.

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	
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	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE continues to seek clarity on the implementation plan. Texas RE understands the Implementation Plan as follows:

- The first bookend for the 10-year verification occurs during the implementation of MOD-026-1 and MOD-027-1. This could potentially be anytime between July 1, 2014 and July 1, 2024.
- The second verification would need to occur 10 years after the first verification, which was done in the time between July 1, 2014 and July 1, 2024 or the Compliance Date for R2-R6, whichever is later.

Regarding this sentence: "When the periodic timeframe falls between the effective date of MOD-026-2 and the Compliance Date for the respective requirement, the Applicable Entity shall comply with the Requirement(s) of MOD-026-2 by the Compliance Date." Texas RE understands this to mean, in the case where MOD-026-2 is approved on 10/15/2022 making the Effective Date 1/1/2023 and the Compliance Date 1/1/2025, the following:

- Scenario 1: The verification occurred on 7/1/2016, making the second verification due by 7/1/2026. In this scenario, the entity would have to do its second verification by 7/1/2026, since the due date is after the Compliance Date.
- Scenario 2: The verification occurred on 8/1/2014, making the second verification due 8/1/2024. In this scenario, entity would have until 1/1/2025 to do the second verification, since the due date is between the effective date of MOD-026-2 and the Compliance Date.

Is this the intent of the SDT's language in the implementation plan? More broadly, in Texas RE's experience, phased-in implementation plans are complex and, in general, not consistently understood by registered entities and Regions. A timeline of examples of implementation would be helpful for the SDT to provide as part of the Implementation Plan materials to avoid industry confusion and corresponding compliance issues.

Additionally, Texas RE noticed that the Implementation Plan uses the term "Applicable Entities." Since the term is capitalized, Texas RE believes that this term should be defined. The term "Applicable Entities" is neither in the NERC Glossary, nor is it defined in the proposed Standard Requirement language. Is it intended that Applicable Entities are the Functional Entities described in Section A4? If so, Texas RE recommends either making this explicit or referring specifically to the Functional Entities listed in Section A4.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

No comment. WECC believes the applicable entities are best suited to respond to this question.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	
Document Name	

Comment

Yes.

Likes 0	
Dislikes 0	

Response

9. Provide any additional comments on the standard and technical rationale for the SDT to consider, if desired.	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Daniel Roethemeyer - Vistra Energy - 5	
Answer	
Document Name	
Comment	
MOD-026/027 should remain seperate and the 5% NCF exemption should remain	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	

The inscrutable language of MOD-027-1 Att. 1 Row 7 has generally been interpreted by GOs and the testing firms they hire as meaning that units normally able to respond only to over-frequency excursions (e.g. combined cycle STGs under sliding-pressure control) can comply via an attestation of unresponsiveness. The REs we deal with have deemed this approach to be acceptable, since (we have been told) this is what the MOD-027-1 SDT intended. A major change is being proposed in MOD-026-2 Att. 1 Row 9, however, which says that one-way-responsive units must be tested.

There is little value to this new requirement, firstly because BES crises seem to always involve underfrequency events, not over-frequency. More importantly, the new models being asked for may be misleading due to reset windup. That is, controllers saturate at maximum output when an STG is running VWO, and the time required to wind down and take command of the HPT control valves generally exceeds the duration of over-frequency events. Combined cycle STGs are therefore usually unresponsive in both directions for normal operation, even though during testing one can drive upward the speed reference signal and hold it constant long enough to force a response.

Likes 0	
Dislikes 0	
Response	

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

1. “Change” is not in the Glossary of terms as it applies to R7 (Attachment 1, Row 6). What qualifies as a change to in-service equipment per R7. When a large synchronous generator (such as a hydro generator) is completely rehabbed, it technically is a change to an existing generator at the plant. It is also considered a new generator as it has a new rotor, stator, turbine, etc. Attachment 1, Row 2 defines the deadline requirements for “Initial verification for a newly commissioned Facility” for R2 and R3. In the example stated above, would a rehabbed generator be a “change” to an existing facility or a “new” facility?

2. As mentioned previously, the Planning Coordinator is brought into the standard unnecessarily, and it would appear beyond the scope of the SARs. Also, NERC currently uses Planning Coordinator, not Planning Authority as is currently drafted in this proposed revision.

3. The standard requirements are filled with many references to the Applicability portion of the standard. However, this is not clear from the requirement text; it is recommended that a clarifying ‘Applicability’ prefix be added to such references in the proposed R2, R3, R4, R5, R6, and as shown in the example below for R2.

4. Many of the more prescriptive modeling requirements (such as relay models and relay types) appear to be in duplication of allowances provided to the Transmission Planner and Planning Coordinator under MOD-032. This should be avoided.

5. As mentioned previously, the addition of protection system requirements found in R2, R3, R4, and R5 is concerning as these did not appear in any of the SARs.

6. Similarly, the addition of EMT model requirements are also not found in the SARs (R1, R6 of the proposed MOD-026-2)

7. For the new proposed R3.2., the new language has removed some of the examples that were helpful under MOD-027 R2.1.5. These examples should be restored if possible. Without these, the new R3.2. language is very vague as to what functions are intended by its description.

8. It is somewhat confusing that the Transmission Planner is required to develop an acceptance process and criteria under R1, but under R8 they are not directly required to utilize the R1 criteria. This could be strengthened in R8's language if R1 is maintained. However, but the Transmission Planner language found in the current MOD-026 R6 and MOD-027 R5 describing the Transmission Planner review process is preferred to the new proposed MOD-026-2 R1 and R8 language re-defining this process. Again, the SARs don't seem to identify a need to revise these requirements so this change would appear out of scope.

9. 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

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

Answer	
Document Name	

Comment

The MRO NSRF recommends the following:

• The MRO NSRF suggests replacing the use of the "365 calendar days" terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

• The MRO NSRF suggests the SDT add specific language for any existing unit newly brought into the scope of this standard. New units or plants need the same "10 year implementation plan" similar to version 1 of MOD-026 and -027. It must be realized that the original 10 year modeling effort will repeat, and the entities charged with this work again need to be permitted to control the schedule so that it can be levelized over time and not overloaded in one small section of the 10 year cycle.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC

Answer	
Document Name	

Comment

Attachment 1 row 4 allows GOs to delay submission of models if a frequency excursion has not occurred. Why is the delay allowed when R3 and R5 state a stage test, or a measure disturbance can be used?

Attachment 1 row 11 should be modified to state that facilities with a commissioning date before 2020 but have been upgraded since 2020 must comply with R6.

The standard allows Generator Owner 365 days to submit models after commissioning or implementing changes. This time fame is too long given the current speed of interconnections. Transmisson Planners will be forced to complete numerous studies before receiving updated models from Generator Owners that reflect what was installed. This delay could result in reliability issues that would have been appropriately identified in the generation interconnections if accurate models were available.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

WEC Energy Group supports both the MRO NSRF and EEI comments.

Likes 0	
Dislikes 0	

Response

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO

Answer	
Document Name	

Comment

The MRO NSRF recommends the following:

{C}· The MRO NSRF suggests replacing the use of the “365 calendar days” terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

The MRO NSRF suggests the SDT add specific language for any existing unit newly brought into the scope of this standard. New units or plants need the same “10 year implementation plan” similar to version 1 of MOD-026 and -027. It must be realized

{C}· that the original 10 year modeling effort will repeat, and the entities charged with this work again need to be permitted to control the schedule so that it can be levelized over time and not overloaded in one small section of the 10 year cycle.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy supports EEI's Comments which state:

EEI recognizes the need for the expanded use of EMT models due to the rapid expansion of IBR resources. Since this effort affects several active NERC projects and it is essential that there is coordination to ensure there isn’t overlapping, conflicting, or duplicative NERC requirements and that enforcement dates are aligned and coordinated. For this reason, the project be appropriately aligned with other approved NERC projects such as Project 2022-04 EMT Modeling, as well as other NERC projects that have elements of EMT modeling included.

The term “Large Signal Disturbance” (see Requirements R6.2, R6.5, Footnote 12) should be defined to ensure a consistent understanding of the requirement where this term has been used.

EEI does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Minnesota Power agrees with MRO’s NERC Standards Review Forum’s (NSRF) comments.

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.

AEP requests that clarifications be made to make it clear that Row 5 in MOD-026-2 Attachment 1 is not in conflict with Row 7 of the same attachment. In the event that multiple identical units are upgraded at the same time so that they remain identical, and continue to meet the criteria of Row 7, only one unit's model would have to be verified at that time and in each 10 year period to comply with the standard, *not each unit at the time of the upgrade.*

AEP believes that in addition to HVDC, FACTS, and Synchronous Condensers, the following facilities would also be brought into scope in the proposed standard, and requests that clarity be added to the technical justification and mapping document to affirm these additional inclusions.

* 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	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

RF appreciates the opportunity to comment on this project, and we appreciate the efforts the Standard Drafting team has taken to address the scope of the two Project 2020-06 SARs approved by the Standards Committee. We request consideration of the comments submitted above, which address factors that prevent our support for the currently posted draft standard and implementation plan.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
To summarize, BPA does not agree with EMT models ever being included in a MOD-026 Reliability Standard revision. BPA recognizes that FERC is supportive of the industry including EMT models. After an EMT Model Reliability Guideline is approved, and the industry has time to absorb the information, EMT Models could be introduced in a new NERC Reliability Standard with an adequate implementation timeframe.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	

Answer	
Document Name	
Comment	

BC Hydro offers the following comments in addition to those provided in response to drafting team's questions above.

1- Section 4.2 Facilities now references “applicable Facility” and “Facility”. BC Hydro suggests that, with the addition of “Facility” as a NERC-defined term in MOD-026, the use of “applicable Facility” is redundant.

2- With the addition of the “Facility” definition in Section 4.2. the Requirements R2, R3, R4, R5 and R6 can be streamlined for legibility.

For example, Requirement R6 can say

“For Facilities identified in Sections 4.2.3, 4.2.4.2 and 4.2.5.1, and 4.2.5.2 each …”

instead of the current wording:

“For inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC identified in Section 4.2.5.1, and VSC HVDC identified in 4.2.5.2, each …”

3- The identification of the Inclusions I2, I4 and I5 of the NERC BES definition in Section 4.2 Facilities does bring clarity; however, the current wording of Section 4.2 Facilities may have a potentially unintended benefit of expanding the MOD-026 applicability beyond BES Facilities. Referring to these Inclusions without the Exclusions specified in the BES Definition will capture in scope of MOD-026-2 resources that would not be otherwise be deemed as part of BES. This appears inconsistent with the NERC Glossary Term “Facility” which is limited to BES Elements, and may be an intended consequence.

BC Hydro recommends adding the phrase “and not subject to any applicable Exclusions” in Sections 4.2.1 to 4.2.4, immediately after referencing Inclusions I2, I4 and I5.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	

N/A

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	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
The Technical Rational document for Requirement 1, Part 1.6 needs to be updated to indicate that MOD-026 Standard Requirement 1, Part1.6 now contains a 90 day requirement. AZPS notes that this effort affects several active NERC projects, and it is essential that there is coordination to ensure there isn't overlapping, conflicting, or duplicative NERC requirements and that enforcement dates are aligned and coordinated. For this reason, the project should be appropriately aligned with other approved NERC projects such as Project 2022-04 EMT Modeling, as well as any other NERC projects that have elements of EMT modeling included. AZPS does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	
Document Name	
Comment	

The Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, APPA/LPPC recommends that webinars should be scheduled for subsequent postings.

Likes 0	
Dislikes 0	

Response

Kristine Howie - Kristine Howie On Behalf of: Kimberly Turco, Constellation, 5, 6; - Kristine Howie

Answer	
Document Name	

Comment

Constellation supports the comments provided by NAGF.

Kristine Howie on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following additional comments:

· Texas RE recommends the language in Requirement R5 match the language in Requirement R4.

- Part 5.1 language match Requirement Part 4.1 language. Part 4.1 states "unit(s) **and** power plant controller" while Part 5.1 says "…unit(s)**,** power plant controller".
- Requirement Part 5.1 also does not have a footnote describing IBR unit as in Requirement Part 4.1.
- Requirement Part 4.2 states "…associated reactive power control system" while Requirement Part 5.2 states "…associated active power/frequency control…"

In Section A5, the title of the Implementation Plan is incorrect. It should read "See Project 2020-06 Verifications of Models and Data for Generators Implementation Plan."

- The implementation plan shows Planning Authority in the Applicable Entities section; this should be changed to Planning Coordinator to match the applicability in Reliability Standard Section 4.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #9.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation supports the comments provided by NAGF.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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

Tacoma Power suggests replacing the use of the “365 calendar days” terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

Tacoma Power supports LPPC’s comments regarding webinars.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	MOD-026-2 Draft 2 Implementation Plan - Suggested Edits.docx

Comment

As we commented on Draft 1, our preference is to keep MOD-026 and MOD-027 as two separate standards.

Additional comments on Draft 2 of the Implementation Plan are included in the attachment.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The NAGF has no additional comments.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	

Document Name	
Comment	

1. Equivalent Unit Verification Condition

At rows 1 and 7 of attachment 1 of MOD-026-02, some changes in the verbiage have been made since last version to avoid confusion around the “Equivalent Unit” topic. At row 7 however, more clarification is still needed to indicate when this row applies. For example, does it apply to row 1 (initial verification), row 2 (newly commissioned facility), row 3 (subsequent verification) and row 5 (change to in-service equipment)? If it applies to all the other rows, please add text to mention it.

2. Unit vs Facility

At row 8 of attachment 1 of MOD-026-02, in the “Verification Condition” column, term “unit or Facility” is used. This differs from all other sections where “Unit” has been replaced by “Facility”.

Also, at row 7, term “unit” is used; should it be “Facility” instead?

3. Non-responsive Facilty

At row 9 of attachment 1 of MOD-026-02, in the “Required Action” column, last paragraph is unclear and should be deleted, as it does not bring any added value. Row 8, which has similar content than row 9, does not include this unnecessary paragraph.

Likes 0	
Dislikes 0	

Response

Cyntia Doré - Hydro-Qu?bec Production - 5 - NPCC

Answer	
Document Name	
Comment	

1. Equivalent Unit Verification Condition

At rows 1 and 7 of attachment 1 of MOD-026-02, some changes in the verbiage have been made since last version to avoid confusion around the “Equivalent Unit” topic. At row 7 however, more clarification is still needed to indicate when this row applies. For example, does it apply to row 1 (initial verification), row 2 (newly commissioned facility), row 3 (subsequent verification) and row 5 (change to in-service equipment)? If it applies to all the other rows, please add text to mention it.

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At row 9 of attachment 1 of MOD-026-02, in the “Required Action” column, last paragraph is unclear and should be deleted, as it does not bring any added value. Row 8, which has similar content than row 9, does not include this unnecessary paragraph.

Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

1. Seminole noticed that the Standard drafting team did not provide a redline from last approved. This makes reviewing all the changes much more difficult. Seminole had believed NERC had adopted a process by which redlines from last approved would be provided with each additional ballot – which this is. Has NERC modified its ballot process and no longer intends to post redlines from last approved, and if not, why was a redline from last approved not posted in this additional ballot?

2. Because the model process verifications detailed in Requirement R2 may involve multiple BCAs, e.g., excitation system, protection systems, etc., if the model verification involve medium impact BCAs, will these actions fall under CIP-013 vendor risk reviews if the verifications are contracted out?

3. Some of the information that is being submitted to the TP and PC entities could be considered CEII. Can the SDT detail out how CEII protections from FERC are applied to these submissions?

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon concurs with comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

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 agrees with the input provided by EEI on:

1 - The need to expand the use of EMT models due to the rapid expansion of IBR resources and the recommendation on the coordination between NERC projects to avoid overlap, conflicts, or duplicative NERC Requirements and enforcement dates.

2 - That the term “Large Signal Disturbance” (see Requirements R6.2, R6.5, Footnote 12) should be defined to ensure a consistent understanding of the requirement where this term has been used.

3 - The applicability date provided in Attachment 1, Row 11 should not be provided for resources installed before the enforcement of this Reliability Standard.

In addition, as noted in the July 2022 input provided by PG&E, we and other entities have currently approved MOD-027-1 exemptions for Requirement R2 that were allowed under MOD-027-1 Attachment 1, Row 7. The R2 exemption was carried forward in MOD-026-2 Attachment 1, Row 8, which PG&E appreciates. PG&E again respectfully requests that the project team add additional language to Attachment 1 that allows for grandfathering of existing exemptions similar to MOD-27-1. This will allow entities to avoid having to re-apply under MOD-026-2, which eliminates administrative and operational burdens that can be avoided.

Likes 0	
Dislikes 0	
Response	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	
Document Name	
Comment	

1. Seminole noticed that the Standard drafting team did not provide a redline from last approved. This makes reviewing all the changes much more difficult. Seminole had believed NERC had adopted a process by which redlines from last approved would be provided with each additional ballot – which this is. Has NERC modified its ballot process and no longer intends to post redlines from last approved, and if not, why was a redline from last approved not posted in this additional ballot?

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3. Some of the information that is being submitted to the TP and PC entities could be considered CEII. Can the SDT detail out how CEII protections from FERC are applied to these submissions?

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Portland General Electric Company supports the comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

ITC supports the comments submitted by EEI

Likes 0	
Dislikes 0	

Response

Joseph McClung - JEA - 1, Group Name LPPC

Answer	
Document Name	

Comment

The Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, LPPC recommends that webinars should be scheduled for subsequent postings.

Likes 2	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre; JEA, 3, Williams Marilyn
Dislikes 0	

Response

John McCaffrey - American Public Power Association - 4 - NA - Not Applicable

Answer	
Document Name	

Comment

APPA members report that the Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, APPA recommends that webinars should be scheduled for subsequent postings.

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

Southern Company does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard. EMT models should be required only for resources meeting all these criterion: a) specifically identified within Requirement R6, b) commissioned after the approval date of this Reliability Standard, and c) specifically identified by the TP and/or PC.

Attachment 1, Row 9 changes the original scope of units responsive to frequency disturbances from bidirectional inclusion to unidirectional inclusion. Many generating units and facilities operate at maximum MW output conditions and cannot provide additional MW for low frequency disturbances (solar, wind, steam turbines at valves wide open conditions, combustion turbines at operating at exhaust gas temperature limits, BESS systems operating at the maximum discharge condition, etc.). Requiring modeling of these situations is unproductive. The transmission planners on the original standard drafting team for MOD-026-1, and MOD-027-1 indicated that they are not interested in modeling over frequency conditions, so wording was added to Attachment 1, Row 7 of MOD-027-1 to provide model verification exemption for unidirectional responding units (**does not respond to both** over and under frequency events). What is the basis for changing this position particularly for units which are unidirectional in the response capability?

Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	
Document Name	
Comment	
The Standards Project webinars are beneficial for entities to understand the changes made in the recent version and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, Santee Cooper recommends that webinars should be scheduled for subsequent postings.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
There are instances where both the PC and TP should be applicable to the requirement, but the SDT appears to point only to the TP. It is recommended that the SDT review the requirements and add both PC and TP where applicable.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	

The SRC wants to thank the Standard Drafting Team for all their dedicated Project work and appreciates the recent drafted changes in organizing the data of Synchronized Facilities and Invertor Based Resource Facilities.

Requesting two additional Requirements:

R10. Each Transmission Planner shall send a Generator Owner or Transmission Owner a written notice to request the model review and verification when:

10.1. There is a mismatch between the simulation result and dynamic event recorded data or PMU data; or

10.2. A technical concern related to a device setting, model parameter value, or the control loop in the dynamic model.

R11. A Transmission Owner or Generation Owner shall provide the evidence in response to R10 for the applicable unit. The evidence may consist of the following:

- Simulation results and recorded event data demonstrating the simulated unit or plant response does not match the measured unit or plant response; or

- Analysis on dynamic model parameter setting or Control loop analysis.

Each Generator Owner or Transmission Owner receiving a notification of denial under Requirement R8 or a model review request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies shall provide a written response to its Transmission Planner within 90 calendar days of receiving a notification or request, in accordance with the periodicity in MOD-026-2 Attachment 1.

Project 2022-04 EMT Modeling SAR recommends that verification and submittal by the GO occurs prior to commercial operation; whereas the MOD-026-02 draft allows for 365 calendar days *after* the commissioning date. However, this can lead to reliability issues not being identified during interconnection studies. Is the SDT's intention to leave addressing this issue to the new drafting team for Project 2022-04 and no alignment or coordination is necessary?

The SRC recommends including the following items in an Implementation Guidance document:

For Section 1.1: Acceptable positive sequence dynamic Model list and level of detail should be based on NERC Eastern Interconnection Reliability Assessment Group (ERAG) or Acceptable Models Working Group (AMWG), Transmission Planner (TP) provided format the new work group that NERC is forming; i.e. the AMWG. Language should also allow the Planning Coordinator (PC) or TP to modify the NERC ERAG listing for acceptable models if necessary. The SRC would also like the PC or TP to have the ability to modify the NERC ERAG/AMWG listing for acceptable models, including user-defined models.

For Section 1.2: The SRC is unsure how a NERC EMT model list would be maintained. Most PSCAD models are uniquely developed for equipment and are black box models with limited modeling information other than inputs and outputs. Once more information is known, consideration should be given as to how acceptable Electromagnetic Transient (EMT) Model list and level of detail should be maintained. Language should also allow the PC or TP to modify the NERC-approved listing of acceptable models, if necessary.

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	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	

a. The technical criteria document is not adequate to show why the items requested are necessary. It just states that they are necessary. There is no data supported study or calculation that shows why these requested items are necessary for reliability.

b. There seems to be no technical basis and method to why EMT models are beneficial.

c. There is no evident technical justification as to why adding outer-loop controls, limiters, and protection into existing models would be beneficial for reliability.

d. There needs to be an assessment of the BES established models per the current versions of the MOD-026 and MOD-027 standards and see how they have been implemented by the TPs. Based on this assessment, we can identify gaps and start forming a technical justification for improvement.

e. The SDT seems to have non- technical consensus to propose these changes continent wide. It would be advantageous to pursue a project of technical justification internally at NERC, Industry Research institutes like EPRI, or Academic Institutions with capacity.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

NVE recommends the following:

NVE suggests replacing the use of the “365 calendar days” terminology with 12 calendar months. This greatly simplifies the scheduling and aligns with MOD-025.

NVE suggests the SDT add specific language for any existing unit newly brought into the scope of this standard. New units or plants need the same “10 year implementation plan” similar to version 1 of MOD-026 and -027.   It must be realized that the original 10 year modeling effort will repeat, and the entities charged with this work again need to be permitted to control the schedule so that it can be levelized over time and not overloaded in one small section of the 10 year cycle.

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 / BANC

Answer	
Document Name	

Comment

The Standards Project webinars are beneficial for entities to understand the changes made in the recent version, and provide an opportunity for entities to ask questions or seek clarification. This second draft did not have a webinar. Due to the complicated nature and potential impacts of these Standard changes, LPPC recommends that webinars should be scheduled for subsequent postings.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

Consideration of Comments suggestion - While due to the similar nature of multiple comments received during the initial ballot and comment period, the SDT has chosen to respond to comments in summary format, this makes it dificult/time consumming for the member to locate where their comments have been consider and if they have been adequately disposition.	
Likes 0	
Dislikes 0	
Response	

Comments submitted by GE

4. Do you agree 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:

- Better clarification is needed for direction on when updated models (positive sequence and EMT) are required. Manufacturers will necessarily update firmware for improved features and accuracy, as well as possible bug fixes. Provided these improvements do not affect electrical performance, these changes should be allowed without re-submission or this will risk delaying helpful software updates. New models and validation should not be required for modifications that do not reflect any material electrical performance impact. Suggest modifying the language in R7 to read "…within 180 calendar days of making a hardware, software, firmware, control modes or setting change…that alters the equipment response characteristic *and results in a material electrical performance impact*…in accordance with MOD-026-2 Attachment 1.
- Better clarification is needed for the definition of "validation" specific to this standard in Footnote 9. While it is clear that validation incudes the comparison of site results to the model responses, it may not be entirely clear that this activity can include calibration of the model prior to submission. Suggest modifying the language in Footnote 9 to read "For the purposes of this Reliability Standard, the term "validation" refers to the dynamic process of testing or monitoring the in-service equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response. *This activity includes the calibration of the model to match the testing or monitoring results, if necessary*. *This may be required, for example, due to the uncertainty of grid strength, or proximity of other IBR plants.*
- Many OEM's maintain user-defined models that are most applicable to their equipment. Language should be added to ensure that Generator Owners can provide these as acceptable positive sequence models, and/or that the validation of generic models may be limited as OEMs do not develop the structure of generic models, only a parameterization.

5. Do you agree 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:

- Better clarification is needed for the definition of large signal disturbance in R6.2. As there does not appear to be a definition in the NERC glossary that could be referenced, suggest that it could be added here, likely in a footnote, to ensure that the understanding of large signal disturbances is clear to all parties for the purposes of validation (fault types, fault depths, governor responsive events etc).

Comments submitted by EEI

1. Do you agree as a whole that Draft 2 of MOD-026-2 is an improvement to Draft 1? If you do not agree, please provide an explanation.

   ☐ Yes
   ☒ No

   Comments: While the changes made to MOD-026-2 are an improvement, we still do not support Draft 2 because of the concerns described in our responses to Questions 2, 4, 5, 6 & 9 .

2. Do you agree 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: EEI does not support the proposed language for R1 because (see comments below and suggested edits to Requirement R1 in boldface):

   - R1.2 is insufficiently clear as to EMT requirements. While Footnote 2 provides clarity, clarifications contained in footnotes are often missed. EEI suggests language that we believe generally aligns with SDT intent but is not contained in a footnote.
   - R1.6 does not provide sufficient time for GOs and TOs to obtain models needed by the TP and PC. We suggest 180 days.

   R1. Each Transmission Planner and its Planning Coordinator, shall jointly develop dynamic model verification requirements and processes. The dynamic model verification requirements and processes shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner, and include at a minimum the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

   1.1. Acceptable positive sequence dynamic models, format, and level of detail;

   1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail **for resources specifically identified within Requirement R6 only, and commissioned after the approval date of this Reliability Standard, and specifically identified by the TP and/or PC**;

   1.3. Acceptance criteria used by the Transmission Planner to determine disposition under Requirement R8 including , at a minimum , the following:

   1.3.1. model parameterization checks;

   1.3.2. model usability, initialization, and interoperability; and

   1.3.3. model submittal requirements.

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

   1.5. Process by which verified model(s) are submitted to the applicable Planning Coordinator, after the model(s) meets acceptance criteria of Part 1.3; and

   1.6. Process for Generator Owner or Transmission Owner to obtain the model(s)contained in the Transmission Planner's database for an existing Facility owned by the Generator Owner or Transmission Owner within **180** days of receiving a written request.

3. Do you agree 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: EEI supports the revised language contained in Requirements R2 and R3.

4. Do you agree 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: EEI supports the proposed language in Requirements R4 and R5.

5. Do you agree 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: EEI suggests the following changes in boldface to Requirement R6, noting that the information in the footnotes should be moved out of the footnotes into the body of the Reliability Standard. Additionally, 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.

R6. For applicable units of inverter based resources (IBRs) per identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC per identified in Section 4.2.5.1, and VSC HVDC per identified in 4.2.5.2, **commissioned after the date identified in Attachment 1, Row 11, the responsible** Generator Owner or Transmission Owner shall provide **an OEM** verified EMT model(s), **that includes all OEM supplied** associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with ~~**the periodicity in**~~ MOD-026-2 Attachment 1. The verified model(s)model(s) and accompanying information shall include at a minimum the following: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1. **Model(s) that contain inverter control modes, control blocks, and protections represented, as applicable and be representative and accurate of the equipment installed at the generation resource.**;

6.2. Device test results demonstrating a comparison of the IBR unit's response and the IBR unit's EMT model response for large signal disturbances. If device test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason;

6.2.1 A device test that is hardware specific may include a factory type test, hardware in the loop test, or other manufacture manufacturer test to ensure the EMT model's large signal disturbance response emulates the supplied equipment to the extent possible, noting that even detailed EMT models of IBR plants, invariably have certain necessary approximations and limitations.

6.3. **OEM supplied EMT facility** model and with associated parameters representing the IBR unit(s), collector system, auxiliary devices, power plant controller, main transformer(s), and enabled protections and controls that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant **that conforms to the following**;

6.3.1 Models are to have the protections and controls that act on voltage, frequency, and/or current, or act on quantities derived from voltage, frequency, and/or current, which directly trip the IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant represented in the supplied EMT facility model. (*Examples of protections that should be included are IBR unit DC reverse current, DC bus over- and under-voltage, DC voltage unbalance, DC overcurrent, AC over- and under-voltage protection (instantaneous and RMS), AC overcurrent, over- and under-frequency protection, feeder (equivalent) AC over- and under-voltage, feeder (equivalent) over- and under-frequency, PLL (or equivalent) loss of synchronism, and phase jump tripping*.)

6.3.2 Model shall be non-proprietary to ensure compatibility with a wide range of modeling software.

6.4. Validation of the Facility EMT model response using the recorded response for a dynamic volt or VAR reactive power or voltage event, and for a dynamic active power or frequency event in which the power plant controller's or other Facility active power controller's perceived frequency deviates per Attachment 1, Note 1, resulting from either a staged test or a system disturbance; and

6.4.1 Exclusion: LCC HVDC facilities are excluded from the dynamic voltage or VAR event portion of the requirement.

6.5. Documentation comparing the response of positive sequence dynamic model(s) of Requirement R4 and R5 to the response of Facility EMT model of Requirement R6 for large signal disturbances.

6. Do you agree 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: The model verification periodicity information contained in Requirements R7, R8 and R9 should be removed in favor of the information provided in Attachment 1. Duplicative periodicity information in these requirement adds unnecessary confusion as to entity obligations. For example:

Requirement R7 states updated verified model(s) or a plan to verify the model per R2, R3, R4, R5 or R6 is to be submitted to the TP within 180 calendar days, while Attachment 1, Row 5 states 180 days is required unless a plan is submitted, then 365 days after submission of a plan is allowed. To avoid this conflict, all model verification periodicity should only be in attachment 1.

Deletion of Footnote 5, MOD-026-1, Requirement 4 (*R4 has been mapped to R7*): EEI is concerned that the deletion of footnote #5 from the MOD-026-1 (i.e., not included in the current draft) has created an area of possible compliance ambiguity and risk for responsible entities. This footnote was previously included in MOD-026-1, R4 to provide clarity over what kind of changes "that alter the equipment response characteristics" are in scope. Moreover, the deletion of this footnote leaves auditors and responsible without clear direction as to the intended scope. For this reason, we ask the SDT to reconsider the deletion of footnote 5 (from MOD-026-1) or to add similarly clarifying language to the next draft.

EEI additionally Requirement R9 needs to include a dispute resolution process in order to resolve disagreements between the TP and GOs and TOs on the acceptability of the models provided.

7. The 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: *EEI will not provide comments on the cost effectiveness of the proposed changes.*

8. The SDT proposes a 1-year implementation plan for Requirements R1, R7, R8, and R9, with an additional 3 years for compliance with Requirements R2-R6 for newly applicable Facilities. For existing Facilities, the Implementation Plan proposes the 10-year reoccurring periodicity is maintained 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: While EEI supports the changes being implemented in MOD-026 by the SDT, the rapid changes being made to require verified resource EMT models for introduction into area and regional EMT studies is out pacing the industry's ability to comply. This includes OEMs and responsible entities who are both being challenged to provide verified EMT models that are non-proprietary and broadly useful to planners. All of this requires the support of a limited number of qualified consultants and necessitates substantial training to ensure responsible entity staff. The SDT should consider a 60 month implementation plan**, specifically 2-years for R1, R7, R8 and R9 and the 3 additional years for Requirement R2-R6,** that would provide responsible entities sufficient time to develop trained staff and allow affected OEMs the ability to develop non-proprietary models that more could accurately reflect the performance of the resources they are suppling to the industry.

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

   Comments: EEI recognizes the need for the expanded use of EMT models due to the rapid expansion of IBR resources. Since this effort affects several active NERC projects and it is essential that there is coordination to ensure there isn't overlapping, conflicting, or duplicative NERC requirements and that enforcement dates are aligned and coordinated. For this reason, the project be appropriately aligned with other approved NERC projects such as Project 2022-04 EMT Modeling, as well as other NERC projects that have elements of EMT modeling included.

   The term "Large Signal Disturbance" (see Requirements R6.2, R6.5, Footnote 12) should be defined to ensure a consistent understanding of the requirement where this term has been used.

   EEI does not agree with the applicability date provided in Attachment 1, Row 11. Responsible entities should not be required to obtain verified EMT models for resources installed prior to the enforcement of this Reliability Standard.