Individual or group. (46 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (46 Responses)
Question 1 (33 Responses)
Question 1 Comments (42 Responses)
Question 2 (33 Responses)
Question 2 Comments (42 Responses)
Question 3 (0 Responses)
Question 3 Comments (41 Responses)

Individual
Nazra Gladu
Manitoba Hydro
Yes
None.
Yes
Although Manitoba Hydro agrees with the concept proposed, it is difficult or sometimes impossible to get an exact match between simulated and measured responses. The drafting team should allow for some engineering judgment (for example, if the responses are within 5-10% of each other, the model could be considered to be a reasonable representation).
Section 2.1.2 - Manitoba Hydro suggests revising the text to read as follows: Manufacturer, model number (if available), and type of excitation control system and the plant volt/var control function (if installed). R2.1.4. - Manitoba Hydro proposes that only the text of "Model structure and data for the excitation control system" is kept. An excitation control system consists of generator and excitation system as per IEEE 421.1 and 421.5. 4.2 - The language immediately preceding the bullets is unclear (i.e. 'that meet the following' should possibly be reworded as 'provided they meet the following'). R1 -This requirement would be clearer if rewritten as 'Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner:' General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?
Individual
Kathryn Zancanella
South Feather Power Project
Applicability section 4.2.2.2 describes an Individual Generating Plant as consisting of multiple generating units that are directly connected at a common BES bus with a total capacity greater than 75 MVA. It would help if there was a proximity element to the definition of "Individual Generating Plant." My question/comment comes from the fact that I have three single unit powerhouses with a combined total capacity greater than 75 MVA connected to a single 115 kV radial line, with several miles of transmission line separating each unit from the other, but the radial line (which is owned by another entity) ultimately terminates at a single (common) point on a BES bus. Attached to this same radial transmission line are a distribution substation and another entity's small hydro plant, so it is not clear how this common point on a BES bus would be characterized.
Individual
xyz
lum
No
No
Individual

Darryl Curtis
Oncor Electric Delivery Company
No
Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
No
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. For MOD-026-1 Section 4.2.4, Oncor takes the position that it is the decision of the PA not the TP who determines the basis for NERC applicability. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the applicability determination in Section 4.2.4, be the responsibility of the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Individual
Jim Watson
Dynegy
Yes
Yes
1. It’s not clear what the difference is between R3 and R5. Suggest combining these into one Requirement. MOD-027-1 which also requires model validation does not have a Requirement similar to R5. 2. Requirement 2.1.1 does not state how much of a step change is required when testing the exciter controls. A commonly used step is 2% but this is not clear.
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
There is a problem with the threshold in the standard of 100MVA units. We would suggest that this be in line with the BES DEF and reduce this threshold to 20MVA. Why has the threshold been increased? If the data has to be provided for LGIA under the Tariff then we should be verifying the data. There is also inconsistency between the

standards posted for comment I.E. PRC-019-1. We would like to see better consistency for the thresholds between all the standards under this project and with the other projects associated with generator thresholds.
Individual
Lynn schmidt
NIPSCO
Verification requirements would be burdensome, e.g., model response by staged testing or comparison with a system disturbance may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
Yes
Yes
N/A
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
Since GO's typically do not have in-house expertise, they would either have to hire consultants to perform model verification or develop in-house expertise, including acquiring simulation software. Are such simulated models/software available today for this on the market? If not, has time been built into the implementation schedule for allowing such creation—it does not appear so? Also, the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location.
No
It appears that without the word "and" in 4.2.4, this criterion of using NERC registration criteria would "trump" all the other interconnection requirements above. But, with the word "and" it indicates that any of the smaller registered units or blackstart resources would only be included in this standard if the Transmission Planner requires. The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.
The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should

be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip overspeed excursion. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed.
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
Group
pacificorp
ryan millard
Yes
Yes
Individual
Winnie Holden
PSEG
Yes
Yes
We voted "Negative" on this standard the reasons shown below. This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: "The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states "Synchronous condensers are not currently addressed in the NERC Registry Criteria" However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency." The SDT responded as follows: "The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex

interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model." In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: "The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2." PRC-019-1: "The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers." We need to see "one" statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1. 2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1, R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all "modelers," the result will be outdated data in someone's model, which can have a bad result. The team should have one broad "data sharing" policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)
Yes
Yes
In general, Ingleside Cogeneration LP believes that a good working relationship between the Generator Owner and Transmission Planner includes a reasonable justification for any request that requires time and expense on the part of the other.
Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to voltage transients can lead to reliability improvements. In addition, the technical veracity and implementation time frames in the latest version of MOD-026-1 are far improved over previous versions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.

Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
For Requirement 6, ATC recommends the wording at the end of the requirement to read "that includes how any of the following criteria are not met:" because the existing wording does not express that the criteria are not met when the model is not usable.
Individual
Ken Gardner
Alberta Electric System Operator (AESO)
1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. 3. Requirement R4, as written it appears owners of generating units that plan to change out the excitation control systems are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration: 1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires"… Verification of an individual unit less than 20 MVA." Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. 2. Applicability Section 4.2. Facilities – ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES).
VSL Requirement R6 – ReliabilityFirst still believes the VSL for Requirement R6 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R6 clearly requires the Transmission Planners to "...notify the Generator Owner... ", while the corresponding VSL states "The Transmission Planner provided a written response to the Generator Owner indicating..." The VSL is adding additional requirements on the TP (i.e. provide written response) which are not required within the actual requirement (nowhere in R6 is the TP required to provide a written response). If it is the intent of the SDT to have the TP provide a written response, ReliabilityFirst recommends adding that language to the requirement.
Individual
Dale Fredrickson
Wisconsin Electric Power Company

No
In Row 4, the use of 350 MVA as the cutoff for “sister unit” treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. Also, in Row 5, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues.
No
We propose that the requirements for a “technically justified unit” must also include the technical reasons why the unit under consideration is critical to the reliability of the BES.
1. In 4.2.1.2, the use of the term “directly connected at a common BES bus” suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g. 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, “one or more of”. 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the actual data on request, not just the instructions on how to obtain it. 4. In R2.1.1, the GO is required to have documentation comparing the “model response” to the “recorded response”, in this case Voltage vs. Time. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT? 5. In R3, the requirements for the written response to the TP need clarification. The term “either” would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. 6. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years.
Individual
Thad Ness
American Electric Power
Yes
The SDT should consider either removing MOD-026-1 R5 or merge R3 and R5 because a) MOD-026-1 R3 and R5 appear to have the same objective with similar wording and b) MOD-027-1 does not have the equivalent of MOD-026-1 R5. MOD-026-1 R6 ends with "...that includes the following:" yet whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"
Group
Tennessee Valley Authority
Brandy Spraker
No
1. Attachment 1, Row Number 4, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),” Justification is that if a GO has units that are equivalent and meet the “sister” criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
No
1. The GVSDT had good intentions by having a very short requirement. However, I am not sure what the intent is. A few more descriptive words would help greatly.
None
Individual
Michael Falvo
Independent Electricity System Operator

No
The long periods in Attachment 1 introduce too much risk: the modeling assumptions (used to derive operating security limits and to make other operating and planning decisions) do not reflect the actual performance of equipment. It would be better for the standard not only to establish the maximum period that Transmission Planners and Generators Owners to complete tasks but also to require the Transmission Planners to establish shorter periods when necessary to reduce the risk to reliability to an acceptable level. In Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet requirements. Emerging from this process is the Generator Owner’s conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed in the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized Experience in Ontario has shown that units that were expected to have essentially the same performance often show much larger differences than expected when tested. What seems like small or obscure differences to a Generator Owner can be critical to a Transmission Planner. Row 4 in Attachment 1 should be amended to require the amount of verification on “sister” units to be accepted by the Transmission Planner. Attachment 1 Row 4 that allows for new or existing units that does not include an active closed loop voltage or reactive power control function should be changed. Given the size of the “applicable unit” virtually all units should be on voltage control unless specifically permitted by the Transmission Planner as is the case in Ontario. The adverse effects to reliability of not being on voltage control are well documented (Note1). The standard should be changed to put the onus on the Generator Owner of units not operating in voltage control to demonstrate continued operation in this mode does not have a material adverse effect on reliability. The standard should requirespecify the a process available for moving an “applicable unit” to closed loop voltage control when the Transmission Planner determines this is necessary. Note1: J.D. Hurley, L.N. Bize, C.R. Mummert C.R,The Adverse Effects of Excitation System Var and Power Factor Controllers, IEEE Transactions on Energy Conversion, Vol 14, No. 4, December 1999
Yes
a. No explicit NERC performance requirements for excitation system are a weakness. In Ontario, generating units are required to materially help regulate voltage as the Transmission Planner sets performance requirements for upper and lower ceilings, voltage response time, and stabilizer characteristics. This standard in its present form allows generators to continue to not materially help regulate voltage provided the documentation submitted to Transmission Planner is consistent with this lack of performance. b. In Ontario, experience has been that the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models; both parties must reach an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. c. The measured performance of the OEL, UEL, stator current limiter or any other automatic control system that alters the behaviour of the excitation system should be part of the Generator Owner submission to the Transmission Planner as limiter performance can affect reliability decisions. No limiter that imposes more restrictive limits than the required short term field and armature current requirements in ANSI/IEEE 50.13 should be implemented without the Transmission Planner’s approval. d. The concept of “applicable unit” should be extended to include static var generators and similar devices. All facilities with an excitation control system and more than 100 MVA of capability should fall under this standard. e. Changes to the generator (e.g. rewinds or active power output increases) will affect excitation system performance. The standard should require re-testing following other modifications that the Transmission Planner can show with simulations will require modifications to the excitation system to improve reliability. For example, turbine replacements often provide increased active power capability. At higher levels of active power, the excitation system can materially change without coordinated changes to over-excitation limiters. f. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit’s model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). g. In Ontario we face resistance when our standards exceed NERC requirements. Would it be possible for the SDT in its response to offer its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, if none of our comments can be adopted into the standard, we would appreciate responses such as: “In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this

standard applicable to wider range of equipment are all practices that will tend to improve reliability." or "In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements" This type of response would help us to continue to augment continent-wide standards with additional requirements to maintain reliability in our part of the interconnection. h. We appreciate the SDT's effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," in Section 5.1 to right after "approved by applicable regulatory approval", and move that same wording to right after "following applicable regulatory approval" in Sections 5.2 to 5.4. Also, the same phrase should be appended to each of the four bullets in the Section "In those jurisdictions where regulatory approval is required:" of the Implementation Plan right after "following applicable regulatory approval."
Group
Southern Company
Shammara Hasty
No
We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
Yes
Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. Sub-requirement 2.1.4 Is not clear – is this data the model block diagram and its parameters? If so, simply state that. SCS agrees with the modifications to the Periodicity Table as they both simplify and clarify the periodicity.
Group
FirstEnergy
Larry Raczkowski
Yes
Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 7 should be a part of Applicability section 4.2 Facilities. The reader of the standard shouldn't have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
Yes
1. Although we agree with the footnote definition for "technical justification", we would like the term "match" be replaced with "simulates or represents". We feel that these terms give more interpretation when comparing. 2. While we agree that a threshold for unit verification is appropriate, we are not clear as to why there would be different threshold for each Interconnection. The SDT should include a Guidelines and Technical Basis section that explains the geographical differences.
1. FE believes that Requirement 6 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision: R6. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 6.1 through 6.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 6.1. The excitation control system or plant volt/var control function model fails to initialize during a dynamic simulation along with suggested areas for investigation, 6.2. A listing of parameters that fail the Transmission Planner's data checks, 6.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 6.4. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria. 6.5. The excitation control system or plant volt/var control function model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint. 2. For clarity, Requirements 3 and 5 are confusing and seems to be the same. We feel the that R5 can be removed from MOD-

026. This will also be consistent with the requirements of MOD-027.
Individual
Patrick Brown
Essential Power, LLC
1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage step-response tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. 7. Sub-requirement 2.1.4 is not clear – is this data the model block diagram and its parameters? If so, simply state that. 8. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. 9. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.

Individual
Wryan Feil
Northeast Utilities
Yes
Yes
No Comment
Individual
Brian Evans-Mongeon
Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion
Mike Garton
Yes
Yes
Dominion agrees with this change; however, is concerned with the phrase “demonstrating that the simulated unit or plant response does not match the measured unit or plant response.” The use of the word “match” implies that the simulated response and measures response must be exact, when in fact this will not likely be the case. This language in section 4.2.4 (and other sections) should allow for acceptable variation so compliance can be properly achieved and demonstrated.
Individual
Mike Hirst
Cogentrix Energy
No
We recommend removing the first element of the logical AND statement of Attachment 1Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
No
The term “technically justified” in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.
1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and

the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage stepresponse tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules Page 5 of 11 up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 6. 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. 7. Sub-requirement 2.1.4 is not clear – is this data the model block diagram and its parameters? If so, simply state that. 8. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. 9. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
Individual
Daniel Duff
Liberty Electric Power
Agree
NAGF
Group
Florida Municipal Power Agency
Frank Gaffney

Related to our comment on MOD-025, if synchronous condensers are only owned by TOs, then the excitation system of a synchronous condenser would not be verified in MOD-026 because it is only applicable to GOs. FMPA recommends that synchronous condenser excitation systems should be verified through the same process, and as a result, if a synchronous condenser is owned by a TO, then a TO should have applicability to it only for excitation systems on synchronous condensers it may own.
Group
Duke Energy
Greg Rowland
Yes
We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Yes
Typo - In the Effective Date section 5.3, strike the word “thirty” after the word “quarter” in the fourth line in the clean version.
Group
MEAG Power
E Scott Miller
Agree
Southern CompanyServices, Inc. - Gen
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Individual
Maggy Powell
Exelon Corporation and its affiliates
Yes
No
Applicability Section 4.2.4 currently states "A technically justified2 unit that meets NERC registry criteria and is requested by the Transmission Planner." With the reference footnote stating "Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response." This intended applicability is confusing and implies that the Transmission Planner has the discretion to decide applicability if a previously exempted unit does not meet Transmission Planner decided criteria. Exelon suggests that this be deleted in its entirety. If the GVSDT intent is to pull in other generating units below the MVA threshold criteria based on Transmission Planner discretion, then that should be factored into Applicability Sections 4.2.1 through 4.2.3. In addition, if Section 4.2.4 is also written to negate an exemption based on Transmission Planner discretion then that provision should be factored into Attachment 1 and not into the applicability section.
Exelon again reiterates that the Standard should specifically define the acceptance criteria. The current draft (draft 4) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not “usable”, if there are technical concerns with the verification documentation, or if the model response did not match the recorded response to a transmission system event. This written response is to contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification. It appears from previous comments of the GVSDT that the Generator Owner has final say on the model and the GVSDT has previously responded "that the standard is written so that the Generator Owner “owns’ the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model’s predicted response.”

While Exelon agrees with this statement; Exelon again requests that this language be clearly articulated within the body of the Standard or that definitive acceptance criteria be added to the Standard.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power System Planning agrees with the revisions made to Attachment 1. Idaho Power Generator Owner- Suggest that "commissioning date" due date requirements be changed to "commercial operation date" to be consistent with other standards.
Yes
Idaho Power System Planning agrees with the revisions made in Section 4.2.4. Idaho Power Generator Owner- The phrase "units that meet the NERC Registry Criteria" has no meaning, since entities and not units are placed on the NERC registry. In addition, demonstrating that a simulated response does not match a measured response is not sufficient technical justification. Additional, technical justification should include demonstration that the different response materially impacts system studes. Additionally, allowing only one year for submission of test results following a technical justification is unreasonable, 5 or 10 years to match the initial implementation time period is more reasonable from the Generator Owner perspective for appropriately planning and scheduling the outage time and work.
1) Technical Justification of units based solely on a simulated response not matching recorded response is insufficient. Technical Jusitification needs to include evidence that the difference in response has a material effect on the conclusions of the relevant system studies. 2) Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work.
Individual
Daniela Hammons
CenterPoint Energy
In R6, CenterPoint Energy recommends changing 90 days to 180 days for a Transmission Planner to notify the Generator Owner that a model is usable or is not usable. Such a change will allow time for model verification through the various regional processes for generator data submittals and dynamic planning case building.
Individual
Kirit Shah
Ameren
No
There appears to be a discrepancy between the language in the requirement R4 and its VSL compared to Row 3 of the Attachment 1. In the both requirement and VSL, a 180 day period is stated, while in Row 3 of Attachment 1, a 365 day period is stated.
Yes
(1)We request that papers listed in the references section of the standard are made readily available on the NERC website. (2)There appears to be an extra word “thirty” in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard. (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models? (4)We still have serious concerns about compliance with new MOD-026-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect. We appreciate the SDT considering our comments on this issue in the last draft, but we still disagree about the potential conflicts for the following reasons: (a)The reporting requirements to comply with MOD-012 are dependent upon the data requirements and reporting procedures put in place by their Regional Entity as mandated by MOD-013. This does not provide consistency across the country. (b)We take data reporting under MOD-012 very seriously and incorporate testing in our program to ensure the data is accurate. Consequently, our reporting and compliance with MOD-012 does involve generator testing on a 5 year basis. (c)Any GO that has implemented a MOD-012 compliance program that involves testing that cannot perfectly synchronize with the 10 year testing in this draft of MOD-026 will have a significant burden in scheduling generator testing to satisfy both standards. (5)We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal

requirements within MOD-026. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country.
Individual
Teresa Czyz
Georgia Transmission Corporation
Yes
Yes
Group
Luminant
Brenda Hampton
Yes
Yes
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 2 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10 year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. (2) Row 3 in Attachment 1 states that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new excitation or plant volt/var control system. However, Requirement R4 also applies to changes to the controls systems. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. (3) Per Requirement R4 and Row 5 in Attachment 1 the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 3 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application.
No
Because NERC and the Regional Entities do not maintain a public list of units that meet the "NERC registry criteria," it is impossible for the Transmission Planner to know for which set of units it may submit a technical justification per R5 and applicability section 4.2.4. The NERC ROP Appendix 5B, Statement of Compliance Registry criteria III.c.1, III.c.2 and III.c.3 each represent fairly "bright lines," where the TP can deduce which units meet these criteria. However, criterion III.c.4 is amorphous and notes on the page 11 of the document give NERC flexibility to deviate from the criteria anyway. Thus, we request that the drafting team either clarify that the "NERC registry criteria" in applicability section 4.2.4 is intended to mean criteria III.c.1, III.c.2 and III.c.3 in section III(c) of Appendix 5B – Statement of Compliance Registry Criteria or that the SDT work with NERC staff to determine how the TP may get a list of units that meet criterion III.c.4 and Note 1.
(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing "Facilities that are directly connected to the Bulk Electric System (BES)" to "generation Facilities that are part of the Bulk Electric System." Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording "will be collectively referred as an 'applicable unit' that meet the following" confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, 4.2.3, and 4.2.4. However, we think the inclusion of the "will be collectively referred as an 'applicable unit'" is superfluous. Because the section is the applicability section, we think this language could be struck for

clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be “generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:”. (2) In requirement R2, please change “for each applicable unit” to “for each of its applicable units.” This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set in the use of attestations in measures in FAC-003-2 M1 and M2. (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle. (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date?
Individual
Don Jones
Texas Reliability Entity
Yes
As TRE stated in previous comment periods to the standard, we disagree with using the 5% capacity factor (Attachment 1, Row 7) to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. We recognize this is somewhat alleviated by Requirement R5, which now provides a method for the TP to request a model verification for a unit that has less than 5% net capacity factor if the unit’s simulated response fails to match its measured response.
Yes
Should Blackstart units have a specific inclusion as an “applicable unit”, regardless of capacity factor or “technical justification”?
1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is “directly connected” to the BES. Please consider reviewing the language to see if it should instead say “included in” the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not “directly connected” to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 2) TRE recommends changing to “Planning Authority or Transmission Planner” in the Functional Entities in Section 4.1.2 instead of “Transmission Planner”. This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners. 3) The timelines are generally too long, which will result in stale, incorrect and generic data being utilized in modeling systems. Consider shortening timeframes.
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No comment on this question
No

No comment on this question.
A stated purpose of Generator Verification is "to ensure that generator models accurately reflect the generator's capabilities and operating characteristics." Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets' capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load's process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load's produc tion schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Russell Noble
Cowlitz PUD
No
Cowlitz supports the comments put together by the NAGF SRT: 1. We recommend removing the first element of the logical AND statement of Attachment 1 Row 4 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location. 2. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 7 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 7 of Attachment 1 to be deleted.
No
Cowlitz is unsure if it is possible to accurately model generation such that modeling software will be able to predict actual plant response to a disturbance. The Standard may create a never ending circle of requests from the TP for improved modeling data. Cowlitz understands that modeling software is still in its infancy, and more research and testing is needed to explore the boundaries between achievable modeling and where unrealistic goals exist.
Cowlitz supports the comments put together by the NAGF SRT: 1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual voltage and reactive power responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard excitation component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-026-1. Such models do not take into account, for example, equipment thermal capability limitations and the capping of reactive power output to respect aux bus voltage limits. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-026-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. online voltage stepresponse tests, low-load rejection during normal stop events), and should lead to definition of specific testing means for definition

of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models, and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event. There are also no specifics regarding how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. It was stated in a 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion did not make it into the standard. 3. The term "rotational inertia" in R2.1.3 should be replaced with "inertia constant (H)," the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. Either way, the obligation to conduct testing in this respect should be waived for units having an OEM-developed value and no modifications to the rotating components, since rotational inertia can be identified more precisely via calculation than by clocking a post-trip over speed excursion. 4. The term "technically justified" in para. 4.2.4 on p.3 and in R5 is too vague, in that the degree of actual-vs.-predicted mismatch triggering MOD-026-1 applicability is not specified. It is also not clear how this comparison is to be made if the Facility did not have to provide a MOD-026 model in the first place. In any event the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 6. 5. The instruction in R4 to notify the TP, "within 180 calendar days of making changes that alter the system response is too vague, despite the attempted clarification in footnote #3, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. 6. Please add clarifying language to R5 to emphasize that this requirement is addressing units that meet the NERC registry criteria but are smaller than the MVA size specified in the applicability section. 7. Sub-requirement 2.1.4 is not clear – is this data the model block diagram and its parameters? If so, simply state that.
Individual
Don Schmit
Nebraska Public Power District
Agree
MRO NSRF

Kathleen Goodman
ISO-New England
No
Row 3 requires model transmittal "within 365 calendar days after commissioning the unit". It is not acceptable in terms of system reliability for a large unit to be operating on the system for 365 days after commissioning without a verified model. FERC approved ISO Tariff language also calls for provision of the model prior to Commercial Operation. The standard would not meet the requirements of the Tariff. Row 7 discusses capacity factor. The capacity factor reference has been removed from the requirements. If the capacity factor is still to be used this is unacceptable from a reliability standpoint. Large generators that have a low capacity factor will be required to operate under extreme conditions when the system is most stressed. A verified model should be provided regardless of capacity factor given this consideration.
Kathleen Goodman
ISO-New England
No
This means that the Transmission Planner can only call for verification following a system event. It is counter to reliability to have to wait for an event to occur to then request verification. The footnote should be revised to include wording for the Transmission Planner to demonstrate an effect on the BES. Certain generators under 100 MVA could affect the BES and with this language verification could then take place.
Kathleen Goodman
ISO-New England
Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software

vendors. Hopefully this can be worked out with the vendors.

Requirement R2.1.3 should indicate the requirement for the total combined turbine/generator inertia constant. Simulations need to study the combined inertia of the turbine and generator not just the generator.
A requirement R2.1.7 should be added to require verification of generator excitation limiter settings.

A requirement R2.1.8 should be added to require verification of supplementary voltage control inputs.

Requirement R3 only requires a "written response" from a Generator Owner to the Transmission Planners notification that a model is not useable. Wording must be included so that ultimately the Generator Owner shall provide a "usable model" to the Transmission Planner.

Requirement R4 must be modified so that models are provided prior to making changes in the excitation control system or plant volt/var control function. It is counter to system reliability to allow generators to modify and subsequently operate equipment without notifying the Transmission Planner.

Footnote 6 should be modified to include ability for the Transmission Planner to require a verified model from a generator under the size threshold if the generator impacts the BES.

Requirement R6 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model does not initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping.