Individual or group. (48 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (48 Responses)
Question 1 (34 Responses)
Question 1 Comments (42 Responses)
Question 2 (29 Responses)
Question 2 Comments (42 Responses)
Question 3 (0 Responses)
Question 3 Comments (42 Responses)

-
Group
Domion
Mike Garton
Yes
Dominion suggests that footnote 1 not contain the capitalized term Wind Farm Verification as this is not defined in either this standard or the NERC Glossary of Terms.
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that “Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability….” It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. The phrasing regarding applicability should be made more consistent. The criterion, “Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System,” in para. 4.2.3 appears to state that a station with two 500 MW fossil units (meeting NERC registry criteria) and a standby, 10 MW diesel genset connecting to the 13.2 kV bus (not meeting the NERC registry criteria), for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory position, however, by saying that “For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group.” This would be better stated as, that “For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group.” Applying on p.16 an “unduly restricted” classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in our comments above are not related to transmission system conditions. Our concerns are amplified by the statement, “Observe auxiliary bus voltage limits,” in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT’s intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus drop-out? Doing so would constitute an unacceptable operational practice. Note 2 should be deleted as well (“While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification….”) since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, “The recorded Mvar values were

adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720 MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently incorrect, given the dictionary definitions of "normal" as meaning standard, usual, typical etc and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range. The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing…," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR test. The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per our comments above. The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," is incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to. Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended.
Without some exemption, we disagree with the GVSDT linking generator applicability of this standard to the Compliance Registry Criteria. Instead, the approach to applicability should be the same as what is used/proposed in MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual units greater than 100 MVA directly connected to the BES, etc.) Other than that size unit, use regional criteria to address any smaller units identified as critical to the BES in a given region. Consistency of criteria among the standards within this Project 2007-09 should be the same.
Individual
Brian Bejcek
Wolverine Power Supply Cooperative, Inc.
Yes
Yes
This standard is redundant. We are already required by MISO to provide real power data. It would be more logical for this standard to be applicable to the RTO because they are already asking for most of this data. I would rather have MISO expand what they are asking for and have them pass the data along to NERC, than to have to comply with two entities asking for the same thing with slightly different methods.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
1. In Attachment 1 Section 2.2.1, we take issue with the requirement to verify reactive power capability at the minimum real power output. We are not convinced this is necessary for BES reliability. The reactive capability at this point can be estimated by the GO with sufficient accuracy for the planning model. Verification of reactive output at minimum real power requires considerable effort and resource scheduling flexibility for data which can be readily estimated without adverse impact to the BES. Especially for large units, it may require a multiple day effort to verify reactive power at the minimum and maximum real power points, due to issues with auxiliary equipment. 2. Attachment 2 On the One Line Diagram and the following data table, it is indicated that the net unit capability is to be provided at the GSU high-side (Point F). This should be revised to allow the GO to provide the net capability at the GSU low-voltage side instead. There may not be adequate metering capability at the GSU high-side, wheras metering at the generator voltage

level is commonly available.
Individual
Jim Watson
Dynegy
No
Recommend deleting the requirement in Attachment 1 section 2.2.1 to verify reactive power at minimum load. This puts the unit in an unstable condition and then stresses it by varying reactive power leading to the increased likelihood of a unit trip.
Yes
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Paragraph 4.2 contains several typos and the intent is not clear. Recommend revising 4.2 to read: "An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."
Yes
In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027.
Group
Southern Company
Shammara Hasty
No
Yes
The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. An engineering study for reactive capability is an option that needs to be allowed by this standard Currently, the standard is more of a performance test than a model verification test – the requirements do not directly fulfill the purpose. Applying an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (page 16) creates a technical error that does not prove or disprove the reactive capability of the generating unit. The D-curve represents the thermal characteristic of a single component (generator). The reactive capability of a generation unit system is also a function of other factors. These other factors include the transmission system bus voltage, GSU impedance and tap setting, unit auxiliary transformer and downstream station service transformer impedances and tap settings, station service bus loadings and voltage limits, and the excitation limiter settings. Staged testing has limitations when attempting to prove a unit's reactive capability. We currently use an engineering assessment approach that establishes a unit's expected reactive capabilities using an analytical model. The model has been validated using historical operational data. The model takes into account all the above factors and is used to estimate the unit's reactive capabilities for extreme system

voltage conditions when unit’s reactive limits will be challenged. The limits are then reviewed by plant operations to ensure any operational limitations have been identified and factored into the assessment. This has proven to be a better process for establishing the reactive limits needed for the transmission planning system models than the use of staged test data. MOD-025 should not require “staged testing” without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the testing. The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability. The recorded Mvar values were adjusted to rated generator voltage, where applicable,” on p.21 should be deleted because it does not make sense to do this.
Individual
Lynn Schmidt
NIPSCO
This is the information that generator owners are supposed to provide every year to transmission owners as part of the MOD-10 data submittal. Why a new standard is being developed instead of modification of the existing MOD-10 is questionable. The burden for complying with this standard falls almost entirely with the generation group, e.g., electric production. Given the above, Transmission Planning recommends a vote in favor of this standard.
Group
Northeast Power Coordinating Council
Guy Zito
If the primary purpose of obtaining net Real Power and net Reactive Power is to build system models to support planning studies, then the Drafting Team should consider that MOD-025 may not be required and could be eliminated. Under Standard IRO-010-1a the Reliability Coordinator can require GOs and TOs to submit Real and Reactive Power data in a format the RC deems necessary. The detailed requirements of MOD-025 can be addressed in IRO-010-1a. 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. If the Drafting Team believes that a separate Standard to verify the gross and net Real and Reactive Power of the turbine generator is required, then MOD-025 should be limited to requiring the reporting of maximum Real and Reactive Power only. In our view the detailed data requirements specified in Attachment 1 and 2 are not required for planning studies. The data in Attachments 1 and 2 have value to plant personal to evaluate unit efficiency and performance, but this data is not needed to support reliability. This data is more relevant to market functions.
Group
Tennessee Valley Authority
Brandy Spraker

No
1. Att 1, Periodicity for conducting a new verification: 1. For staged verification; recommend changing the allotted time to make a change to 12 months. From Att 1: "... of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months" - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. 2. Att 1, Periodicity for conducting a new verification: 2. For verification using operational data; recommend changing the allotted time to make a change to 12 months. Att 1: "... discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months" - change to 12 months. Justification is based on the possibility of generator temporary derates lasting more than 6 months due to seasonal conditions, outage schedules, economic dispatch, etc. Twelve months is more realistic. 3. Att 1, Periodicity for conducting a new verification:, 1 For Staged verification; and 2. For verification using operational data; both steps require verification at least every five years. Recommend verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, "6 calendar years." Justification is to coordinate protective system relay testing during plant outages with the real and reactive power testing that can be performed during outage shut-down or start-up. 4. Attachment 1, 3.6, add "voltage ration and," as follows: The existing GSU and/or system interconnection transformer(s) voltage ration and tap setting. Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies "transformer(s) tap setting"; Attachment 2, had data entries for "Voltage Ratio." Both values are legitimate transformer parameters. 5. Recommend Att 1, 4., be titled as "Record the following auxiliary load information:" Justification is that the current "step 4" is more of a substep to this new "step 4" description. 6. Recommend Att 1, 4., current step text be moved to a substep 4.1, "Develop a simplified key one-line diagram ... " Justification is that this step is similar to the current "steps 4.1 and 4.2" 7. Recommend renumbering steps "4.1 to 4.2" and "4.2 to 4.3." Justification is to change the current "step 4 to 4.1." See items 4 and 5, above. 8. Recommend changing the current "step 4.2 / recommended step 4.3" to read as follows: "If an adjustment is requested by the TP, then develop the relationship between test conditions and generator output so that the amount of Real Power that can be expected to be delivered can be determined from a generator at different conditions, such as peak summer conditions [remove can be determined]... " Justification is to reword for clarity.
1. Entire Attachment 2, recommend linking Att 2 data entries to Att 1 requirements by adding (e.g. Att 1 requirement ______) in parenthesis, to each Att 2 line/bullet. Justification is to define the source requirement for the data. 2. Attachment 2, Summary of Verification, recommend adding the following bullet under "Transformer Voltage Ratio: ..." Add: "Transformer Tap Setting: GSU ____, Unit Aux ____, Station Aux ____, Other Aux ____" Justification is to be consistent between Attachment 1 and Attachment 2. Current Attachment 1, 3.6, identifies "transformer(s) tap setting"; Attachment 2, had data entries for "Voltage Ratio." Both values are legitimate transformer parameters. 3. Overall Standard, The focus of this standard appears to be on testing rather than on verifying the limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test. Justification is that the requirements do not directly fulfill the purpose. 4. Overall Standard, recommend removing the requirements to perform "staged testing." Justification is that staged testing should only be required if requested by the TOP. Justification is that verification of the true reactive limits via staged testing often produces less than optimal results because of transmission system constraints. 5. Standard, 4.0 Applicability, The unit size applicability for MOD-025-2 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027 (i.e. MOD-026-1 Draft, 4.2, Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ...(including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ...(including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ...(including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.)
Group
Pepco Holdings Inc and Affiliates
David Thorne
Agree
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
Yes

Yes
N/A
Individual
Nazra Gladu
Manitoba Hydro
No
General Comments - There is reference to certain actions that would be ‘desirable’ although not strictly required by the standard. This type of language can be problematic if the entity is held to this, or asked to explain why they did not meet the ‘desirable’ level. There appear to be requirements embedded in the attachment, and there should be no requirements here. For example, the word “shall” should be removed (since it implies a requirement) from (i) page 15 (clean version) “If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled . . . . .” and (ii) page 16 “ . . . then the next verification shall be by another staged test, not operational data:” Another example which sounds like a requirement is on page 17 “Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.” Additionally, in 4.2 (i) “TP” should be expanded to Transmission Planner and (ii) the first sentence is worded poorly and should be clarified. Section 2.1 - Manitoba Hydro recommends removing the words “over excited” and replacing the words “normal (not emergency)" with "nominal". Section 3.7 - “(real or reactive)” should be changed to “(real and reactive)”. Page 15 (clean version) - The word “Load” should not be capitalized. Page 17 (clean version), Note 1 - Manitoba Hydro suggests replacing ‘improper tap settings’ in Note 1 which reads “…such as rotor thermal instability, improper tap settings,…” with “improper voltage ratios”. Page 18 (clean version), Note 5 - Manitoba Hydro suggests removing Note 5 which reads “Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.” Such descriptive wording is not required in a standard and should be left for reference books.
Yes
None.
1. 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? 2. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled “Consideration for early Compliance” with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1).
Group
pacificorp
ryan millard
No
PacifiCorp does not support the minimum one hour hold requirement for verifying a generating unit’s maximum real power and lagging reactive power in Section 2.1.1 of Attachment 1. The one hour hold is excessive and fails to correlate to how a machine responds to a system event that only lasts for a few minutes. The one hour requirement also puts unnecessary stress on plant equipment and directly contradicts the WECC Synchronous Machine Reactive Limits Verification Guideline that recommends holding a unit for a minimum of 15 minutes. PacifiCorp has followed this guideline since it was approved in 1996, and recommends this same standard to be applied in Attachment 1.
Yes
Group
Bonneville Power Administration
Chris Higgins
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 it.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Xcel Energy questions the reliability value of determining the maximum leading reactive power value at maximum real power output. This is not an operating regime for most generating units, so operational data will not be available, and operating at maximum power would normally occur during higher system load conditions when the loss of a generating unit due to a mistake during a test would stress the system more severely.
Individual
Michelle R. D'Antuono

Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)
Yes
In our view, Ingleside Cogeneration LP believes the technical language used in the latest version of MOD-025-2 Attachment 1 has been refined to an acceptable point.
Yes
Ingleside Cogeneration LP agrees that the ability for Transmission Planners and other operating entities to be able to rely on a generator's available real and reactive capacity under system duress is essential to BES reliability. In addition, the technical veracity and implementation time frames in the latest version of MOD-025-2 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 (R1 and 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
ATC recommends the following changes: Attachment 1, Periodicity for new verification Item 3 – Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or a mutually agreed verification date." Attachment 1, Verification Specifications Item 2.1.2 – The wording is unclear near the end of Item 2.1.2. ATC recommends this be changed to read, "Reschedule the test of the facility within six months after being unable to test at or above the 90 percent threshold".
Individual
Ken Gardner
Alberta Electric System Operator (AESO)
1. In section 4.2 The AESO considers the existing applicability for reactive power verification 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. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect.
Individual
Thad Ness
American Electric Power
Yes

Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by: a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner…" b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval," and before "each Generator Owner…". 2. There are four measurements of "Gross Reactive Power Capability" for generators: over-excited and under-excited at minimum and maximum active power outputs. Which one of the four measurements should be recorded in Appendix 2 under "Gross Reactive Power Capability"?
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
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
Seattle City Light
paul haase

No
Attachment 1, Section 2.1 explicitly states to run each unit at maximum real power and lagging reactive power for a minimum of one hour. Due to constraints of the load, water flow, or other operational characteristics such as generators' thermal limits this is typically not possible.
No
The VSL associated with Attachment 1 Section 2.1 will often be violated, because due to constraints of load, water flow, or other operational characteristics such as generators' thermal limits it is typically not possible to to run each unit at maximum real power and lagging reactive power for a minimum of one hour as required.
Individual
Daniel Duff
Liberty Electric Power LLC
Agree
NAGF
Group
Florida Municipal Power Agency
Frank Gavvney
A synchronous condenser can be owned by either a TO or GO. For instance, there are installation of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO whoever owns the synchronous condenser.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Although supportive of the standard drafting team’s efforts, LES believes MOD-025 could be further enhanced in consideration of the following recommendations. - Recommend Attachment 1 “Periodicity for conducting a new verification” be revised to require verification of the Real Power capability on an annual basis with Reactive Power remaining at every 5 years. In consideration that regions such as the MRO and SPP maintain existing procedures requiring members to perform Real Power verification at a minimum of annually, LES believes this reduced timeframe is not only reasonable but also achievable for entities. Additionally, it seems reasonable to expect a re-verification be performed if the Real Power is reduced by as little as 5 percent as several units with that level of lost capacity could be significant in adversely affecting the integrity of the BES. - Recommend Attachment 1 “Verification specifications for applicable Facilities” Part 3.4 be modified to specify the duration of the verification period and that the data supplied should be an average of the verification test period. - Per the standard, the purpose of MOD-025 is to ensure accurate information is available for the planning models in order to assess BES reliability. NERC annually builds 4 seasonal peak models (summer, winter, spring and fall) in addition to a spring minimum model. Within these models the TPs must provide Real Power maximum and minimum values and up to 10 sets of correlated real and reactive values in order to model a generators “D curve”. As such, LES would recommend that the GO develop these values and provide them to the TO. While Real Power Max is tested it is only done under the conditions of a single season, it would then be up to the TP to adjust the MW output for the other 3 seasons. LES believes the GO is the more appropriate person to make these adjustments rather than the TP. Additionally, Real Power minimum testing is not addressed within this standard. LES believes with the increase in highly variable generation, such as wind, generators may end up operating at their minimums much more than they have done historically and therefore Real Power minimums should be verified on an annual or 5 year basis as well. In terms of Reactive Power generation, a GO should be required to go beyond what is required in the current Attachment 2 and align with the number of correlated Real/Reactive sets which the TP is required to provide in their models to NERC. - In further support of BES reliability, LES recommends that the net Real Power output for generating facilities be adjusted based on a high temperature for the month based on the model that the Real Power output is being developed for, i.e. summer, winter, spring, fall, or minimum model. The criteria for determining what should be used for a high temperature adjustment point could be an average of the entity’s high temperature for the month over a ten-year period or possibly the 0.4% ASHRAE temperature could be used. LES believes it would not be unreasonable to expect that data be supplied by the

GO for the seasons required for model submission by the TP.
Group
MEAG Power
E Scott Miller
Agree
Southern Company Services, Inc. - Gen
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum (NAGF)group for MOD-025.
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power System Planning as a Transmission Owner that owns synchronous condensers agrees with the revisions made to Attachment 1.
Yes
Idaho Power System Planning agrees with the revised VSLs.
Idaho Power System Planning as a Transmission Owner that owns synchronous condensers has the following comments for the GVSDT to consider: Attachment 1 - Item 2.1.1 lists the verification duration for a synchronous generating unit at maximum real power and maximum reactive power with a one hour testing duration. Idaho Power System Planning comments that the voltage schedule may be difficult to maintain during a one hour test at maximum reactive power for a one hour test during for N-0 system conditions. Idaho Power System Planning asks the GVSDT to consider a 30 minute testing duration for performing the verification to be consistent with the 30 minute duration established for operators to make manual system adjustments following contingency events. Attachment 1 - Item 2.1.2: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for variable generating units. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for variable generating units for the maximum reactive capability test. Attachment 1: Idaho Power System Planning comments that it is unclear what the maximum reactive capability testing duration is for synchronous condensers. Idaho Power System Planning asks the GVSDT to include the minimum testing duration for synchronous generators for the maximum reactive capability test. Requirements to submit verification with 90 days of test date are unreasonable. 365 days is more reasonable, and is consistent with MOD-026-1 and MOD-027-1.
Individual
John Yale
Chelan PUD
Yes
Yes
1. It is unclear how auxiliary load should be calculated where several units share a common station service power supply and all units are not in operation (multi unit hydro plant). Suggest some guidelines in allocation

in these cases should be included. 2. It may not be possible to generate maximum real power for one hour for hydro with small reservoir volumes. Similar to run of river hydro, reservoir volume or other license requirements may restrict this ability. Suggest a similar allowance in these cases to the run of river power qualificaiton. 3. R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which engineering analysis is required for model verification. 4. It may not be possible to test full reactive capability at minimum power for hydro units due to the broad capability curve without exceeding TOP established voltage schedules. I suggest going to some percentage of the "full" value to verify the curve with concurrance of the TOP and TP in these cases or test documentation of limiter settings. If the GO is requried to perform staged test, the TOP and RC must be able to support it. Some system should be established where this can not be done.
Individual
Robert Casey
Georgia Transmission Corporation
Yes
Yes
Individual
Maggy Powell
Exelon Corporation and its affiliates
No
Attachment 1 (general comment): Exelon appreciates the addition by the GVSDT of the exclusion that nuclear units are not required to perform Reactive Power verification at minimum Real Power output (Attachment 1 Section 2.2.3); however, as stated in the previous comments, Exelon still is concerned that nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with nuclear plant specific NRC operating license. In response to Exelon's comments in the 9-27-12 Consideration of Comments, the GVSDT states that they "disagree with not requiring a verification to define the unit's reactive capability" and further states that they are "aware of nuclear units that have been safely tested to their leading power factor limits." Although the GVSDT may purport that it is safe to perform such testing there is not one unique design for a nuclear generating unit in the NERC Regional Entities. Exelon continues to believe that there should be a provision in the Standard to allow for such an exemption based on considerations for nuclear unit regulatory, unit stability or other potential equipment restrictions. To address the concern that the GVSDT has related to providing a blanket exemption for nuclear units, Exelon suggests that such an exemption must be justified, documented in writing, and accepted by the Transmission Planner. Exelon suggests that a new note be added to Attachment 1 as follows: "If a unit is restricted due to other regulatory, unit stability, plant operating procedures, or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate. A generating unit with such a restriction must be justified, documented in writing and accepted by the Transmission Planner." Periodicity for conducting a new verification: Attachment 1 Section related to the periodicity for conducting a new verification (page 15 of 22) second paragraph states: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." Experience shows that maintaining the plant’s substation bus voltage within the scheduled voltage range at some arbitrary value is often inadequate to allow maximum VAR output during staged Reactive Capability testing. In such cases the system operator would need to adjust the substation voltage, potentially close to a schedule limit. Exelon suggests that the sentence be revised as follows: "The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measure to coordinate with the Generator Operator to adjust the plants substation bus voltage as required to accommodate the desired reactive output."

No
Although Exelon agrees with a majority of the revisions, it does not seem reasonable to assign a Severe VSL for a potential administrative oversight for not submitting the data to the Transmission Planner within a set period of calendar days equally to a complete failure to perform the required testing for an applicable generating unit. Exelon suggests that the administrative requirement for submitting data within a set period be limited to maximum of a High VSL and the application of the specific submission time periods be adjusted for the Low and Medium VSLs and the Severe VSL be revised to reflect inability to produce sufficient data to substantiate that the required testing was performed (i.e., the Generator Owner may have performed the test but is unable to produce any data to support the testing). As an example, the proposed example revision to the Severe VSL is as follows: The Generator Owner failed to produce data upon request of the Transmission Planner. OR The Generator Owner failed to verify the [applicable test] per Attachment 1 of an applicable generating unit.
Section D, "Compliance," Part 1.2, "Evidence Retention," (page 6 of 22) first paragraph is unnecessary and redundant since the retention periods specified are for the time period since the last compliance audit. Exelon suggests that this paragraph be deleted in its entirety.
Individual
Kirit Shah
Ameren
No
While it is a step in the right direction to direct the Transmission Operator to take measures to maintain the system bus voltage of the plant under test at an acceptable level during the reactive power capability testing of the plant, this still does not mean that the plant would necessarily be able to reach its full reactive power output capability during the test. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then we believe that there needs to be some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed.
No
There seems to some discrepancy in the reporting date that the VSLs are based on when using the operational data to verify. The first section in the VSL for R1 is worded slightly differently than the same portion of the VSL for R2 and R3. For R1, the reporting date seems to be based on the date that the data is selected for verification based on historical data, whereas for R2 and R3 the reporting date seems to be based on the date when the historical operating point was reached. Please clarify the SDT's intention to have such a difference, as it could make a big difference in meeting the reporting date deadline, and cause confusion among Generator Owners.
(1)We believe that for sets of generators that are designed and operated identically, there should be a provision allowing use of "Sister Units" for compliance as done in MOD-026. (2)We believe the 5 year cycle with a 66 month limit is too stringent. We request that due to possible outage scheduling issues or other impacts, extending this 66 month limit by 18 months allowing a maximum of 84 months between test verifications. (3)Was it the intent of the SDT to leave out a minimum verification time of one hour for both MW and MVAR verification? Could the SDT please clarify their intention and if a minimum of one hour was intended?
Group
Luminant
Brenda Hampton
Yes
No
Luminant disagrees with the expanded VSLs and recommends that the SDT return to the VSL list in the previous posting. Luminant believes that the original VSL list is comprehensive and does not require expanding to include completeness of the data reported, or specific compliance to items, 1, 2, and 3 of the "Periodicity for conducting a new verification."
Individual
Don Jones
Texas Reliability Entity
No

1) Attachment 1, 2.2.2: We recommend changing the reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. 2) Attachment 1, 2. We disagree with the statement that "…previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). Unless there is a documented system limitation, an accurate test should result in 90% or better of the D-curve, after correction for ambient conditions. 3) Attachment 1, 2.2 does not require wind and photovoltaic "applicable facilities" to verify Reactive Power capability at a minimum Real Power output. The ISO may still have reactive requirement for renewable resources at minimum output levels. If so, the resource should be required to demonstrate and test against those requirements? 4) Attachment 1, 2.1.1: What is the basis for "one hour?" Attachment 1, 3.1 says to record the value at the end of the verification period. What is the expected value(s) to be provided for the hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and wind turbines may not allow for a full hour. Current ERCOT regional criteria for the Reactive Power leading and lagging test duration is 15-minutes. 5) Attachment 1, 3.2: If there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. 6) As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. 7) Attachment 1, section 3: Generator Owner should also include the D-curve with the verification data. For many air-cooled units, the real and reactive capability can vary significantly with ambient temperature. The Transmission Planner needs both the ambient temperature and the D-curve data to verify the validity of the test. 8) Attachment 1, 3.4: we suggest re-wording to "… perform corrections to Real Power ***and Reactive Power*** for different ambient conditions…"
1) Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning and Operations models for specific periods. 2) In section 4, the phrase "directly connected to the Bulk Electric System" may have the unintended consequences of excluding a generator unit connected to the BES through a 69/138 kV autotransformer (for example). Suggest removing 'directly' from these requirements. 3) 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. 4) TRE recommends changing to "Planning Authority or Transmission Planner" in the requirement sections instead of "Transmission Planner". 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. 5) The Functional Entities are listed as the Generator Owner and the Transmission Operator. However, the VAR standards have the Transmission Operator provide the Generator Operator a voltage or reactive schedule and require the Generator Operator to maintain that voltage or reactive schedule. Should the Generator Operator be included in this standard for verification and data reporting? There are many cases where the Generator Owner is not the Generator Operator and confusion could result (or incorrect data/testing) if different criteria were provided. 6) Overall the timing is too long. Waiting 12 calendar months for verification impacts reliability. Based on this requirement, the capability could be reduced by 50% but not tested for 12 calendar months (or longer). That could put significant strain on a local system that may not be tested for an extended period and yet be compliant with the standard.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
(1) We believe that Attachment 1 is clearer but we still have a few issues that the drafting team should address. In response to our previous comments, the drafting team indicated that a staged test is required prior to the use of operational data. In other words, the first verification must be through a staged test. The response to comments cited a sentence in sub-section 2 of the "Verification specifications for applicable Facilities:" in Attachment one as the reason. Essentially, it says if the previous test was unduly restricted, then the next verification should be a staged test. We do not think this is straight forward. What if there was no test? Could a test that did not occur be called unduly restricted? It would be much clearer for the drafting team to state directly either in Attachment 1, the requirements, the implementation plan or the effective date section that the first test must be a staged test. (2) In subsection 3.4 of the "Verification specifications for applicable Facilities:" section of Attachment 1, we disagree with including "Other data as applicable." It is ambiguous, open ended and will only lead to inconsistent enforcement. Who decides what is applicable? The TP? The GO? The auditor? What happens if an auditor decides they believe a piece of data should be included but the TP and GO agree it shouldn't? If the other needed data cannot be enumerated, an open ended statement such as the one discussed here should not be added as a "catch all." This type of statement is

unduly burdensome.
Yes
(1) What measure does the effective date use when determining percentage of applicable Facilities that must be completed by the given date? Is it a percentage based on the net nameplate rating of the generator? We suggest this should be stated directly to avoid conflicts between what the auditor assumes versus what the registered entity assumes. (2) Attachment 2 discusses subtracting tertiary real and reactive power to get net real and reactive power, yet there is no entry for it. Should there be an entry added in the form? (3) The response to our last comments regarding inclusion of the last verification column indicated that a note would be added to indicate that this column would be blank for the initial verification. We could not find the note. Please add it. We were concerned a similar issue to the one experienced with the Protection System Maintenance and Testing standard would be experienced. In the PRC standard, auditors interpreted statements in the standard to require data prior to the enforceable date even though registered entities were not required to keep it. It resulted in a number of violations. (4) In applicability sections 4.2.1 through 4.2.3, please change “directly connected to the BES” to “that are part of the BES”. Per the BES definition, generation units can be and are part of the BES. Using “directly connected to the BES” could draw in a non-BES unit. (5) How will mothballed units be handled? If a mothballed unit is returned to service, is it treated like a new unit with the return date serving as the commissioning date?
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No comments on this question.
No
No comments 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 production 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. Additionally, the SDT should define the term ‘Synchronous condenser’ so that it is clear that a large synchronous motor is not a synchronous condenser.
Group
Duke Energy
Greg Rowland
No
Delete Note 3 on page 18 of the clean version, and delete the reference to Note 3 located on page 15 under “Verification specifications for applicable Facilities: #2”. If a unit is equipped with AVR, the test must be conducted with the AVR in service.
Yes
1) Attachment 2, Summary of Verification – Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) In the Consideration of Comments Report the Standard Drafting Team agreed to make this change, but it was overlooked. 2) The focus of this standard appears to be on testing rather than on verifying the P and Q limits to be used in Transmission Planning models. The standard is more of a performance test than a model verification test – the requirements do not directly fulfill the purpose. 3) Leading VAR Staged Testing – Leading VAR staged testing provides little benefit to the BES and should only be performed once in an initial staged test or validation. The fact that the regions will not be able to provide operational data for the leading VAR test points requested, proves that the system usually doesn’t

require leading VARS. In the situations such as system recovery and lightly loaded BES where leading VARS may be required, the initial testing and validation that the unit's heat removal capability (such as lagging VAR operational data) is sufficient, should serve as satisfactory verification of the unit's capability. The risk (and cost) of repeated operation of the unit in the maximum leading VAR is not warranted for the little benefit it provides to the BES. The risk of Step Iron degradation and loss of synchronous operation every five years far outweighs the benefit such testing would provide the BES once the unit has been proven capable. The lagging VAR capability test or validation will prove that the unit's heat removal capability has not been compromised. MOD-025-2 should be reworded to only require periodic validation (either by staged testing or operational data) for lagging VARS, and that periodic leading VAR testing only be required if the unit is not capable of passing the lagging VAR capability test or validation. 4) Applicable Facilities – Verification of units between 20 MVA and 100 MVA provide little benefit to the BES for the risk and cost of performing the staged test for these units. The maximum VAR contribution for these units is in the 5 to 20 MVAR range, and the risk and cost for testing, documentation and auditing of units of this size is not warranted for the small benefit gained. If there is a specific need for a particular small unit to provide VAR support due to regional constraints, then it should be validated. But to require validation for all the small units that have little impact on the reliability of the BES, the cost is not warranted. The unit size applicability for PRC-019-1 and MOD-025-2 should be set equivalent to that specified by MOD-026 and MOD-027 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery, NERC Reliability Compliance Coordinator
No
Attachment 1, Parts 2.2.1 and 2.2.2, AECI does appreciate adequate Attachment 1 allowances for voltage-schedule restrictive operating conditions, so that actual Maximum and Minimum reactive capabilities that simply cannot be attained, are not required, as acknowledged per Notes 1 & 2. However we do question the value to industry, beyond initial testing per this standard, of the 5-year retesting and believe this Requirement will eventually be removed unless redrafted per responsible entities' internal controls program expectations. We do however agree with the requirement to retest when unit conditions change sufficiently to warrant retesting.
Yes
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Group
SERC Planning Standards Subcommittee
Charles Long
Yes
Paragraph 4.2 contains several typos and the intent is not clear. Recommend revise 4.2 to read: "An adjustment may be requested by the TP to develop the relationships between test conditions and generator output at different conditions, such as peak summer conditions. If so requested, test results should be adjusted to ambient conditions specified by the TP. Adjusted results should be submitted to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."
Yes
In attachment 1, change the periodicity for performing Real and Reactive Power capability verification from five years to ten years. This would be consistent with standards MOD-026 and MOD-027. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Russell Noble
Cowlitz PUD

No
Cowlitz supports the comments developed by the NAGF SRT: 1. The 90-day limit for historical data in R1.2 and R2.2 conflicts with the statement at the bottom of p.15 that "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability…." It is also unclear how the day on which verification data are collected can differ at all from the verification date, much less by two years. 2. The semantics regarding applicability should be made more consistent. The criterion, "Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System," in para. 4.2.3 appears to state that a station with two 500 MW NERC-registered fossil units and a standby, non-NERC-registered10 MW diesel genset connecting to the 13.2 kV bus, for example, needs testing only for the large units because the diesel is not part of the NERC-defined Facility. Para. 1 at the bottom of p.15 appears to take a contradictory position, however, by saying that "For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." This would be better stated as, that "For generating units of 20 MVA or less that are included as part of a Facility greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group." 3. Applying on p.16 an "unduly restricted" classification to reactive power verification results that fall short of 50% of the thermal capability curve (D-curve) constitutes a technical error that is fatal to the approvability of MOD-025-2 in its present form. The D-curve deals only with a single characteristic (temperature) of a single component (generator), and the reactive capability of a generation unit system is generally set by other factors. Lagging PF is frequently restricted to less than 50% of the D-curve value due to variation of aux bus voltages beyond the IEEE-recommended range of +/- 5% for normal operation, and it is not uncommon for stability issues to preclude any leading-PF operation (nuclear units in particular never operate at leading PF). Potential lack of leading capability is acknowledged in Note 4 of Att. 1, but contradicted by the p.16 references discussed above. All explicit and implied connections in the draft standard between the expectable reactive power capability and the generator OEM D-curve should be expunged. 4. Note 1 of Att. 1 (pp. 17-18) is inaccurate and should be deleted. The limitations described in comment #3 above are not related to transmission system conditions. Our concerns are amplified by the statement, "Observe auxiliary bus voltage limits," in Note 1 from the previously-voted-on version of MOD-025-2 having been deleted from the present draft. Is it the SDT's intent that units should import and export reactive power to the generator OEM D-curve regardless of whether or not there is risk of tripping due to aux bus dropout? Doing so would constitute an inacceptable operational practice. 5. Note 2 should be deleted as well ("While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification….") since there is no quantitative indication of what these other conditions should be or what such an analysis would mean. The line, "The recorded Mvar values were adjusted to rated generator voltage, where applicable," on P.21 should also be deleted. 6. Clarification is needed regarding the requirement in para. 2.1 of Att. 1 to verify capability, "at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications." It is understood that a unit typically running for example at 720 MW in the summer and 740 in the winter could be reported at either value, depending on when the verification was performed; but the term "normal maximum" is inherently an oxymoron, given the dictionary definitions of "normal" as meaning standard, usual, typical, etc. and "maximum" as representing an extreme condition. Para. 2.1 should be changed to read, "within the Facilities' normal (not emergency) range of full load Real Power output at the time of the verifications," to indicate that readings within the dotted lines in the graph below are what's wanted, not the heavy, solid line. Note that normal power is never a single value, it is a range. It would be helpful to include a diagram on the subject, along with any statistical criteria involved in defining NERC's concept of the normal range. 7. The statement on p.15 that, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing…," should be expunged. A considerable operational period must be reviewed to determine what the normal full-load real power range is, as explained in comment #4 above, and it is impossible to go back in time and insert a VAR test. 8. It would be helpful to state any coordination of units within a plant that is required or preferred for VAR testing. Running for example a three-unit plant with all units exporting MVARs together, then all importing together, will produce more conservative reactive power capabilities (i.e. the aux bus limits will sooner be encountered) than is the case for testing units one at a time with the other two under normal operation. Pull-together/push-together is the more realistic approach, however, for simulating the response of the plant to a Disturbance of the BES. 9. The reference to "maximum Real Power" in para. 2.2.2 of Att. 1 should be changed to match the terminology in para. 2.1, after modification per comment #6 above. 10. The requirement in para. 3.4 of Att. 1 that one record, "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions," are incomprehensible. It appears to indicate that in some cases ('if applicable") the GO may require that ambient corrections be performed, and in other cases they won't; but there is no indication when and if such calculations are mandatory, and there is no hint as to the reference conditions that GOs are supposed to correct-to. 11. Para. 4 of Att.1 should state that the simplified key one-line diagram need be no more detailed than that shown in Att. 2. Development of diagrams showing all aux transformers and real and reactive power flows would be unduly burdensome, and the wording of Att. 2 indicates that such a level of detail is not intended. 12. GSU losses should have a separate line in Att. 2, since they are not specifically a

tertiary load (item C in the Att. 2 diagram). 13. MOD-025 should not require “staged testing” without option. Staged testing should only be required if requested under TOP-002-2b R13. This will ensure the appropriate system conditions exist to support the testing (coordinated by the TOP and RC). This eliminates the GO from being required to perform testing that cannot be supported by the TOP and RC. Industry experience has shown that verification of the true reactive limits via staged testing is typically not possible due to transmission system constraints. Due to these constraints, an option to use engineering analysis for validation should be allowed by this standard. While the standard could allow staged testing as an option, we believe that staged testing should only be considered when there is a demonstrated need for the testing. 14. We do not see significant value in a 5-year re-verification cycle through staged testing. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. Possible equipment problems are being used as reason by some for wanting staged testing and periodic re-verification. Equipment problems that could limit real and reactive power capability generally manifest themselves during normal operation. These are appropriately addressed via normal operational reporting to satisfy requirements in TOP-002-2.1b and VAR-002-2b and are corrected through normal maintenance practices. Therefore, we do not agree that concerns for equipment problems justify periodic testing of every generator in the BES. Furthermore, that approach will subject the BES to a constant state of testing and off-normal operational conditions that we believe could actually prove to be detrimental to BES reliability.
Individual
Don Schmit
Nebraska Public Power District
Agree
MRO NSRF