Unofficial Comment Form

Project 2007-09 Generator Verification

MOD-026-1 and PRC-024-1

**Instructions**

Please **DO NOT** use this form for commenting.  Please use the [electronic comment form](https://www.nerc.net/nercsurvey/Survey.aspx?s=59257b1c944d405fa07f3ce9648fd6ee) to submit comments on the proposed revisions to MOD-026-1 and PRC-024-1.  Comments must be submitted by **March 29, 2012**.  If you have questions please contact Stephen Crutchfield at [Stephen.crutchfield@nerc.net](mailto:Stephen.crutchfield@nerc.net) or by telephone at 609-651-9455.

**Background Information**

The Generator Verification Standard Drafting Team posted MOD-026-1, Verification of Models and Data for Generator Excitation Control System and Plant Volt/Var Control Functions, and PRC-024-1, Generator Performance During Frequency and Voltage Excursions, from June 15 through August 1, 2011 for a 45-day concurrent comment/ballot period. Stakeholders were asked to comment on several aspects of the standard.

**MOD-026-1**

The GVSDT asked stakeholders if they believed any additional generation configurations should be considered for applicability under this standard. None of the comments identified other generation configurations/types that should be covered in the Applicability. Several commenters recommend making the standard applicability match the compliance registry, while other commenters recommend removing the requirement to verify small generator units from the standard applicability. The SDT believes:

* The standard is drafted to provide the proper cost/benefit balance for performing generator verification.
* It is not necessary to have models verified for all units listed in the compliance registry.
* Proposed applicability thresholds will substantially improve the accuracy of the excitation models and associated reliability-based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by the MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds which correspond to at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Concern was raised that the language of R5 could require verification of units with ratings less than the thresholds specified in the registry criteria. The SDT asserts that any unit not included in the standard Applicability and deemed to require verification as justified by the Planning Coordinator must, by definition, satisfy the Registry Criteria threshold established. The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit. This is not the case.

A few commenters expressed concern that the standard does not require the Generator Owner to notify the Transmission Owner of new equipment and provide the Transmission Planner preliminary models based on OEM design data. The SDT reminds that the scope of the draft standard is model verification, which can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process.

Also in response to industry comments, the SDT has inserted a footnote in the standard to make clear that standby generator models are not required to be verified.

The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers.

The GVSDT received many comments concerning various aspects of the standard. As a result of these comments, the SDT has made a number of modifications to the standard including:

1) Correcting several VSL grammatical errors and ensuring consistency between the VSL “increment for tardiness” time period specified and the requirement language.

2) An additional condition was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed-loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations, other than switching capacitor and reactor banks in and out of service.

3) The format and column information of Attachment 1 has been revised for clarity.

4) The typographical errors in R2.1.1 language has been corrected to clearly state expectation that, “The unit or plant’s model response matches the recorded response for a voltage excursion at the generator or plant point of Interconnection from either a staged test or a measured system disturbance.”

5) The language of R2.1.4 has been revised to align with the style of R2.1.6.

6) Several commenters expressed concern with the new Requirement R5 added to the standard giving the Planning Coordinator authority to require a model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the requirement could be misused inappropriately. In addition, R5 language has been revised for clarity.

7) To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).

8) There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability/Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.

As a reminder, the SDT, in its response to industry comments, points out this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.

**Periodicity Table (Attachment 1) for MOD-026-1:**

Based on industry comments from the last posting, the SDT modified the Periodicity Table (Attachment 1) in an effort to convey the required periodicity of model verification in a simple but complete format. The following examples are offered by the SDT to aid industry in understanding the proposed model verification periodicity:

Periodicity Example 1:

The following timeline depicts a model which is initially verified, and then is verified again after a 10-year period. The requirements detailing activities by exception do not occur (R3 – R5) – which is expected to be the situation for the majority of the time. Regarding the third verification (which is not shown on the example below), the GO would need to record and collect equipment response for a voltage excursion on or before the unit’s 10-year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation (i.e., response has to be collected on or before Year 20), and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 21):

Periodicity Example #2:

The second example is much like Example #1. The only difference is that for the second verification, the equipment response for a voltage excursion was collected on the unit’s 9.5 year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation. Regarding the third verification (which is not shown on the example below), the GO would need to record and collect equipment response for a voltage excursion on or before the unit’s 10-year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation (i.e., response has to be collected on or before Year 19.5), and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 20.5).

Periodicity Example #3:

The third example details a scenario which the SDT anticipates would rarely occur. Specifically, the scenario assumes that at sometime after the initial verification, the Generator Owner receives written notification that there is evidence that the model does not accurately predict the actual response of the equipment. As detailed in Requirement 3, the Generator Owner has 90 days to respond to the notice. The Generator Owner may respond that the model is still appropriate, or submit model changes – or it may submit a plan to re-verify the model. The example below assumes that later – i.e., the Generator Owner submits a plan to re-verify the model on the 90th day. From that point, per the Periodicity Table, the Generator Owner has 365 days to record and collect equipment response for a voltage excursion and then an additional 180 days to transmit the model and documentation to the Transmission Planner. Regarding the third verification, the GO would need to record and collect equipment response for a voltage excursion on or before the unit’s 10-year anniversary date of the collection of the recorded unit excitation control system and plant volt/var control response used for the current validation (i.e., response has to be collected on or before Year 17 and 90 days) – and transmit the model and documentation to the Transmission Planner no later than 365 days later (i.e., by Year 18 and 90 days).

**PCR-024-1**

The GVSDT proposed two new definitions for Voltage Excursion and Frequency Excursion. A slight majority agreed with the proposed definitions. The majority of “No” votes disagreed with the voltage excursion portion of the question, while there was only one vote disagreeing with the frequency excursion portion. After reviewing all comments the SDT made the following changes:

1. The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.

2. Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the “no trip” zone.

3. Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per-unit- voltage-base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES). In addition, the definition was modified to include the phrase, “Voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve.”

The GVSDT proposed Requirements R1 and R2 to detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Stakeholders were asked if they believed that the draft of these two requirements, including Footnote 1, clarified that a Generator Owner is not required to have protective relaying installed or set for these functions. Stakeholders generally agreed that Footnote 1 does clearly state that a Generator Owner is not required to have protective relaying installed or set for frequency or voltage protection. Many of the stakeholders made additional comments beyond the scope of the question regarding the intention of Requirements R1, R2, and R3 and provided clarifying language examples. In response, the SDT made the following changes:

1. The Requirement Parts were removed from Requirement R1. Part 1.5 is now Part 1.1. The requirement now reads:

“R1. Each Generator Owner that has generator frequency protective relaying[[1]](#footnote-1) activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the “no trip zone” of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. A generating unit or generating plant is allowed to trip within the “no trip zone” if the frequency rate of change is more than 2.5 Hz/sec.

1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.”

1. Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining parts were modified to clarify intent. The requirement now reads:

“R2. Each Generator Owner that has generator voltage protective relaying1 activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip as a result of a voltage excursion (at the point of Interconnection ) that remains within the “no trip zone” of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit2 or generating plant [Violation Risk Factor: High] [Time Horizon: Long-term Planning].

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner’s study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner’s voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the “no trip zone” of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the “no trip zone” specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment.”

3. Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed. The requirement now reads:

“R3. Each Generator Owner of an existing generating unit or generating plant shall document each equipment limitation (excluding generator frequency and voltage protective relay limitations) that prevents a generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer’s advisory *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

• The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.

• The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard).”

During the Quality Review process prior to the previous posting, a new Requirement R4 was added based on the comments of the reviewers. This resulted in requirement numbers being incorrect for Questions 3 and 4. The GVSDT will ask these two questions again on the upcoming comment form for the successive ballot. A summary of the comments received is in the following paragraphs.

**Relating to question 3 of the previous posting:** The GVSDT added Requirement R5 to allow owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information was intended to provide Transmission Planners with information useful in performing planning studies. In the comment form, the question erroneously asked about R4, rather than R5. A few commenters made comments regarding R4, while the vast majority commented related to R5.

Several commenters felt that there is no additional reliability gain in Requirement R5. Their comments indicated that the information is not useful and that there is little technical value in this information. A few commenters expressed the opinion that it is very difficult, if not impossible, to predict the consistent response of the balance of (a generating) plant to the system excursions shown in Attachment 1 & 2. Further, several commenters expressed the opinion that it is unlikely that any steam plant will survive for the entire “no trip zones” of the attachments. Other less frequent comments included the following:

• R1-R4 adequately fulfill the purpose of the standard.

• Standard requirements should be limited to devices that directly respond to the Generator V and F – write standard to exclude all aux system equipment.

• The TP needs only to know when the protective relaying V-t and F-t will trip the unit so the models can switch the generators off when the simulated V and F levels are reached.

• 30 days is too short for a response.

Based on comments received, the GVSDT revised R5 (which is now R4) to:

“R4. Each Generator Owner of an existing generating unit or generating plant shall provide an estimate of that unit’s performance during Frequency/Voltage Excursions to each requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operato,r or Transmission Planner that monitors or models the associated generating unit or generating plant) within 60 calendar days of receipt of a written request to ensure the accuracy of planning studies and system modeling studies. The estimate shall include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning].

4.1. An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of Interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit or generating plant will remain connected for longer than 10 minutes, the estimate should indicate the existing unit or generating plant is not expected to trip.

4.2. Identification of the basis for the estimates developed for 4.1 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.”

**Relating to Question 4 of the previous posting:** The question mistakenly referred to Requirement R5 due to changes to the standard made in response to the Quality Review. This error was observed by the stakeholders and the SDT believes the responses accurately reflect the feelings of industry to the intended question. The slight majority of stakeholders agree with the requirement, while some stakeholders indicated that they do not feel the requirement is technically achievable. Based on the comments received, no major changes were made to Requirement R6 (now R5).

The GVSDT proposed voltage ride-through tables for High Voltage Ride Through (HVRT) and Low Voltage Ride Through (LVRT) time durations in Attachment 2. These tables specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Stakeholders were asked if they agree with the proposed times in the tables. A majority of stakeholders agreed with the time values. Many of those that responded in the negative to the question indicated that they felt the 600 seconds duration was acceptable but had other concerns with the standard. No substantive suggestions were made for revising R6. As a result, the GVSDT did not make any changes to Attachment 2.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

*Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.*

# *Questions 1- 5 pertain to MOD-026-1 and Questions 6-8 pertain to PRC-024-1.*

# Questions

1. The GVSDT has added an additional condition to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed-loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service. Do you agree with this concept? If not, please explain in the comment area below.

Yes

No

Comments:

1. The GVSDT has provided guidance on the periodicity aspects of Attachment 1 (see above). Do you agree? If not, please explain in the comment area below.

Yes

No

Comments:

1. Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. Though not a change from the previous posting, the SDT emphasizes for clarity that only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) or units that are already registered (for reasons such as being required to by their RRO) are subject to Requirement R5. Do you agree with the revisions to applicability and to Requirement R5? If not, please explain in the comment area below.

Yes

No

Comments:

1. To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions. Do you agree with this revisions? If not, please explain in the comment area below.

Yes

No

Comments:

1. Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-026-1?

Comments:

1. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.

Yes

No

Comments:

1. Requirement R5 requires a Generator Owner’s new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.

Yes

No

Comments:

1. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-024-1?

Comments:

1. Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit. [↑](#footnote-ref-1)