Unofficial Comment Form

Project 2007-09 Generator Verification

# MOD-025-2, MOD-027-1 and PRC-019-1

Please **DO NOT** use this form to submit comments. Please use the [electronic comment form](https://www.nerc.net/nercsurvey/Survey.aspx?s=e2092c1de78c4f87830c2a47bb8871be) to submit comments on the proposed revisions to MOD-025-2, MOD-027-1 and PRC-019-1. Comments must be submitted by **April 16, 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 GVSDT posted the draft standards June 15 – July 15, 2011 for a formal comment period. Based on stakeholder feedback, the GVSDT made revisions to the standards. A number of commenters suggested revisions for clarity that were accepted by the GVSDT. Minor changes were made to the standard to incorporate those suggestions.

**MOD-025-2**

Language was added to recommend that the AVR be in automatic control while conducting reactive capability testing, but that reactive capability testing must be done even if the AVR is not available. The following language was also added to allow flexibility if 90 percent of the generation is not available when testing wind turbines or photovoltaic inverters:

“If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold.”

When polled, most stakeholders agree with combining MOD-024-1 and MOD-025-2 into a single standard. Several commenters suggested that the standard be clarified to indicate that Real and Reactive Power testing may be performed under separate tests. The GVSDT agrees and has separated R1 into two requirements to allow for separate Real and Reactive Power testing. The intent of these requirements remains unchanged. Requirement R1 now deals with Real Power testing only, while Requirement R2 deals with Reactive Power testing. The measure and VSL for R1 were also revised to match the requirements.

R1. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

1.1. Verify the Real Power capability of its generating units in accordance with Attachment 1.

1.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

R2. Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1. Verify the Reactive Power capability of its generating units, and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.

2.2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.

A statement was also added to the beginning of Attachment 1 for additional clarity:

“It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”

There was an error in the question relating to the Transmission Owner on the previous comment form. The question should have asked if the Transmission Planner was the appropriate entity, rather than the Transmission Owner. Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-2. The GVSDT is confirming this with an additional question on this topic in this posting.

With regard to correction factors for verifications, many commenters pointed out there are many factors that affect generator Real Power output, and these factors are different for different types of generating units. The GVSDT has revised the standard to include any parameter that the Generator Owner determines is required to make the ambient correction in Attachment 1:

3.4. The ambient conditions at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

• Ambient air temperature

• Relative humidity

• Cooling water temperature

The standard gives the Transmission Planner the discretion to request ambient condition correction at time of verification.

There was overwhelming stakeholder support for verifying synchronous condensers as a reactive resource under MOD-025-2. Some stakeholders suggested that consideration be given under this or a different standard for verification of other reactive resources.

The SDT added the following sentence to Attachment 1 in response to a stakeholder comment for clarity:

“If a unit is operated in synchronous condenser mode as well as generation mode, the unit should be verified in both modes.”

There was an error in the comment form for the question regarding synchronous condenser size. The question should have included a 20 MVA limit, rather than 50 MVA. Many stakeholders suggested including the 20 MVA limit. While some commenters suggested values higher than 20 MVA, technical justification was not provided for a value exceeding the generator registration criterion of 20 MVA. The GVSDT will confirm this with an additional question on this topic in the next posting.

Commenters have identified regional variances currently in effect as required by MOD-024 and MOD-025. It is anticipated that these regional standards will be retired once MOD-025-2 is approved. Language provided by Reliability*First* staff has been added to the implementation plan concerning the Reliability*First* standards:

“It is the intent of Reliability*First* to perform a review of both the MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC Board of Trustees approval of the associated NERC MOD-025-2 standard. The purpose of the review would be to ensure that any duplicative requirements or any requirements which are less restrictive or do not add additional detail will be considered for retirement. The steps outlined in the Reliability*First* Reliability Standards Development Procedure will be followed for any such revisions or retirements.”

**MOD-027-1**

The GVSDT expanded the applicability of MOD-027-1 to include plants/facilities comprised of multiple small units, such as variable energy resource plants/facilities. Stakeholders were asked whether they were aware of other generation configurations or types that should be covered in the Applicability. The vast majority of industry agrees that all of generation configurations or types that should be included in the Applicability section are specified in the current draft of the standard. A few minority comments were received suggesting that the Applicability section proposed should either be expanded or reduced. The GVSDT believes industry supports the current draft of the proposed Applicability.

The GVSDT did not propose a requirement in MOD-027-1 where the Planning Coordinator can request a review of a turbine/governor and Load control and active power/frequency control system model for a unit not specified in the standard Applicability section. This was discussed in relation to the proposed MOD-026-1, where a Planning Coordinator may request excitation control system information for a technically justified unit. The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next. Stakeholders were asked if they agreed with this approach. The majority of industry comments support the GVSDT proposal not to include a requirement allowing the Planning Coordinator to request a model review for a unit not specified in the standard Applicability section. There is minority opinion suggesting that such a requirement should be developed; with some commenters also questioning the basis for the Applicability section and the capacity factor philosophy. Most of the minority comments were received from one reliability region and, as such, the GVSDT suggests that region should consider developing a regional standard containing a more stringent applicability. The Planning Coordinator can still request a model review; however, the review is not mandatory under the standard requirements.

Based on industry comments received, the following modifications to the proposed standard have been made by the GVSDT:

1) Corrections of various typos in the body of the standard, the VSLs, and in Attachment 1

2) Extended the time to comply with Requirement 1 from 30 to 90 days

3) Modified Attachment 1 (Periodicity Table) to address units which are always base loaded (by definition a base-loaded unit is considered verified)

4) Modified Attachment 1 (Periodicity Table) to clarify establishing the Initial 10-Year Unit Verification Period Start Date

5) Reduced the maximum time allowed between capture of an event and completing model verification from two years to one year

6) Referenced the NERC GADS document for references to capacity factor in the draft standard

7) Included partial load rejection as a potential test to obtain a recording of the equipment response to be used in model verification

**Periodicity Table (Attachment 1) for MOD-027-1:**

Based on industry comments from the last posting, the GVSDT 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 GVSDT to aid industry in understanding the proposed model verification periodicity:

Periodicity Example 1:

The following timeline depicts a scenario where the Generator Owner has recorders installed before its effective start date for R2 (3, 5, 7, or 9 years, shown as Year 0 in all four examples), and ready to capture the frequency response of the unit to an ambient event. The Generator Owner has decided to not perform a staged test. The first time the unit is operating in a frequency responsive mode and is subjected to a BES frequency excursion, as specified in Criteria 1, as specified in the Periodicity Table, the Generator Owner records the unit’s Real Power response and then has one year to verify the model and transmit the model and documentation to the Transmission Planner. In this example, the first event with the unit in the proper operating mode occurred exactly at Year 3. Also, this example assumes that the Generator Owner took the entire year allowed to finish verifying and transmitting the model to the Transmission Planner exactly at Year 4. Once the model is initially verified, the expectation is that it will be verified again after a 10-year period. For this scenario, the requirements detailing activities by exception do not occur (R3 – R4), which is expected to be the situation for the majority of the time. Thus, per the Periodicity Table, the Generator Owner must begin to monitor for suitable ambient events for the second verification one year before the unit’s 10-year anniversary date of the collection of the recorded unit response used for the current validation (Year 12). For this example, it is assumed that the event occurs sometime between Years 13 and 14; and from that point, the Generator Owner would have one year to complete the verification and transmit the model and documentation to the Transmission Planner.

Periodicity Example #2:

The second example is much like Example #1. The only difference is that for the second verification, two years passed before the first time the unit was operating in a frequency responsive mode and was subjected to a BES frequency excursion, as specified in Criteria 1, as specified in the Periodicity Table. This would also mean that for the third verification, active monitoring for an ambient event would need to begin at Year 23 (1 year before the 10-year anniversary of the collection of the previous event data used for verification):

Periodicity Example #3:

The third example assumes that the Generator Owner chooses to perform a staged test. For the first verification, the staged test has to be performed on or before the effective start date of R2 (3, 5, 7, or 9 years – shown as Year 0 on the timeline below). For simplicity of the example, the timeline shown assumes that the staged test for the first verification is performed exactly on the effective date. The requirements detailing activities by exception do not occur (R3 – R4); which is expected to be the situation for the majority of the time. For the second verification, another stage test is performed exactly on the Year 10 anniversary date of the initial staged test. Regarding the third verification (which is not shown on the following timeline), the GO would need to perform the staged test and collect the associated date on or before the unit’s 10-year anniversary date of the staged test 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 #4:

The fourth example details a scenario in which the GVSDT anticipates would rarely occur. Initially, before Year 8, the Example #4 is identical to Example #1. However, the scenario assumes that eight years after the effective date of R2, the Generator Owner performs an activity which changes the equipment response. As detailed in Requirement 4, the Generator Owner has 180 days to determine if updated model data can be provided, or if the model needs to be re-verified. The example timeline below assumes that later; i.e., the Generator Owner submits a plan in 180 days to re-verify the model. From that point, per the Periodicity Table, the Generator Owner begins to monitor for an appropriate ambient event while the unit is in a mode that it is expected to govern. Once the ambient event has occurred, then the Generator Owner has an additional year to transmit the model and documentation to the Transmission Planner. In this example, the ambient event with the unit in the proper operating mode occurred in three years after the Generator Owner decided to verify the model (i.e., Year 11.5), and the Generator Owner completed model verification and transmitted the results to the Transmission Planner at Year 12.5. Therefore, for the next verification period, active monitoring for the next ambient event begins at Year 20.5 (one year before the 10-year anniversary date of the recorded event used for the current verification). The example timeline goes on to assume that an event was captured two years later (Year 22.5), verification completed with documentation submitted to the Transmission Planner one year later (Year 23.5).

**PRC-019-1**

The majority of stakeholders agreed with the proposed standard and provided some comments for revisions to the standard. The Applicability to Transmission Owners was clarified to include only those that own synchronous condenser(s) as follows:

4.1.2 Transmission Owner that owns synchronous condenser(s).

The GVSDT asked stakeholders if they believed that the proposed PRC-019-1 standard was written to be "technology neutral," such that it can be used for all forms of generation connected to the BES. The vast majority of stakeholders believe that the standard is technology neutral. Several stakeholders that expressed concerns commented that the standard may not work for photovoltaic or wind technologies. The GVSDT agrees that while some of the standard elements might not apply to all technologies, most elements in the example diagrams (in general) would apply to all technologies.

One stakeholder recognized that the SSSL calculation plot used in the example diagrams is based on a fixed-field current, which would require the excitation system to be in Manual Mode. The GVSDT, having previously considered this and knowing the excitation system to typically be in Auto Mode, per VAR-002, provided the following response: The calculation of the SSSL based on a fixed-field current value is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex.

The GVSDT asked stakeholders if they agreed with the applicability to synchronous condensers. The question contained a limit of ≥50 MVA, while the standard contained ≥20 MVA. The GVSDT intended for ≥20 MVA to be the correct number. Many stakeholders pointed out this discrepancy and agreed with the ≥20 MVA threshold. The GVSDT will ask this question again in this posting (see Question 1 below).

Some stakeholders suggested higher MVA limits for units applicable to this standard. The GVSDT based the applicability criteria on the current Compliance Registry Criteria and the current posted draft of the BES definition, both of which currently set the applicability threshold at 20 MVA for individual units. The SDT felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition.

Constellation Power pointed out that repeating the Compliance Registry Criteria within the standard is not wise since the standard must be changed if the Compliance Registry Criteria changes. The SDT agrees with this logic but felt it was necessary to include the appropriate Compliance Registry Criteria within the standard because the standard also applies to synchronous condensers, which are not explicitly mentioned in the Compliance Registry Criteria. If the Compliance Registry Criteria language for generating units was not included in the standard, the standard could be interpreted to apply only to synchronous condensers and not to generators.

Stakeholders were asked if they thought that variable static reactive sources that are not located at generating facilities should be included in the standard. The vast majority of stakeholders did not see a reliability need for including variable static reactive sources that are not located at generating facilities. This equipment is normally protected for internal failures and do not have similar equipment protection such as synchronous generators using generator field limiters and over- and under-excitation protection. The SDT has determined that variable static reactive resources not located at generating facilities are outside the scope of this project. For these reasons, including static reactive resources not located at a generating facility, are not part of this standard.

The majority of stakeholders agreed with the Purpose Statement of PRC-019-1. The GVSDT revised the Purpose Statement of the standard for clarity based on stakeholder comments. The revised Purpose Statement is:

To improve the reliability of the Bulk Electric System by ensuring coordination of generating unit/facility or synchronous condenser voltage regulating controls and limit functions with generator capabilities and protection system settings.

The proposed effective dates provide a “phased-in” approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/facilities. The majority of stakeholders agreed with the phased-in approach. Stakeholders pointed out that, for jurisdictions where regulatory approval is not required, the 100% completion item was missing. The GVSDT added item 5.2.5:

5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees’ approval, each Generator Owner and Transmission Owner shall have verified 100% of its applicable units.

Stakeholders were asked about Section G of the standard which provides examples of how the coordination can be demonstrated. The majority of stakeholders agreed with the information provided, and several stakeholders made suggestion for clarifying language. Specific changes were made to Section G of the standard based on comments received. These changes included:

1. The example diagrams added that they are drawn at nominal voltage and frequency.

2. The formula for calculating the radius of the SSSL was corrected.

3. The items “under-excited limiters or minimum excitation limiters” and “over-excited limiters or maximum excitation limiters” have been placed in the bulleted list of the standard.

4. The SDT changed “protective” to “protection” within the standard to be consistent with Section G.

5. The SDT added a reference document for use in calculation of SSSL.

Several commentators were concerned that Section G has a prescribed method for illustrating coordination of AVR limiter/protection functions with other protection systems. The SDT agrees that there are numerous ways of demonstrating coordination, and does not prescribe any particular method. Any protective function that is enabled should be evaluated for proper coordination.

The SDT reviewed the requests to remove the distance relay and volts/hertz relay elements from the standard. It is the belief that these two elements remain in the document since a) the distance element should illustrate coordination with field-forcing controls of the AVR, and b) the volts per hertz function can operate with the unit on-line under certain operating conditions.

**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 1-4 relate to MOD-025-2, Questions 5-8 relate to MOD-027-1, and Questions 9-11 relate to PRC-019-1.***

1. **The GVSDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below.**

Yes

No

Comments:

1. **The GVSDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below.**

Yes

No

Comments:

1. **The GVSDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? 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-025-2?**

Comments:

1. **The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? 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. Do you agree? If not, please explain in the comment area below.**

Yes

No

Comments:

1. **The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? 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-027-1?**

Comments:

1. **The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below.**

Yes

No

Comments:

1. **The GVSDT revised section G based on stakeholders’ comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide “Equivalent tables or other evidence.” Do you agree with the revisions to Section G? 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 PRC-019-1?**

Comments: