Name (38 Responses)
Organization (38 Responses)
Group Name (27 Responses)
Lead Contact (27 Responses)
Question 1 (60 Responses)
Question 1 Comments (65 Responses)
Question 2 (59 Responses)
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Question 6 Comments (65 Responses)
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Question 3 Comments (65 Responses)
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Question 6 (39 Responses)
Question 6 Comments (65 Responses)
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Question 7 Comments (65 Responses)

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Question 8 Comments (65 Responses)
Question 9 (45 Responses)
Question 9 Comments (65 Responses)

Group
LG&E and KU Energy
Brent Ingebrigtson
No
Either the Planning Authority of the Transmission Planner are the more likely entity to submit data rather than the Transmission Owner as indicted in R2.3
GO’s typically correct to back pressure. Any other adjustments should be performed by Transmission Operator
No
Blackstart unit testing is covered in he EOP standards, and should not be included in the MOD standards. Most of these are smaller units that don’t have much impact on the BES but are important because they are blackstart—not for the VARs.
The addition of the lagging and leading at (2); the expected minimum Real Power output are new points to test from the existing version of MOD-025. This will eventually double the testing window (at a minimum)
Group
Northeast Power Coordinating Council
Guy Zito
Yes

No
The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Yes
Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
No
Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Yes
Yes
No
Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.
Yes
Yes
Yes
Yes
No
No
No
No
No

A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
No
Can’t generators be operated as synchronous condensers if needed?
No
No
Yes
In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
No
This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
No
Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Yes
Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage]. Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
No
Modify the wording to reflect all ‘real and reactive power sources,’ not limiting it exclusively to traditional rotating machinery.
Yes
Yes
No
The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
No
Yes
Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve

is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Group
Imperial Irrigation District (IID)
Sammy Alcaraz
Yes
Yes
Yes
THE REAL POWER DATA OBTAINED FROM GENERATORS IS BASED ON AMBIENT TEMPERATURE AND ADDITIONAL ENVIRONMENTAL AND SYSTEMATIC CONDITIONS. BECAUSE OF THIS REASON, OBTAINING A CORRECTION FACTOR CORRESPONDING SOLELY TO THE AMBIENT TEMPERATURE FOR CALCULATION OF THE REAL POWER WILL NOT BE AN EFFECTIVE APPROACH. IN ADDITION, DUE TO SEVERAL PARAMETERS AS A FUNCTION OF THE REAL POWER AND THE TEMPERATURE, CALCULATION OF AN ACCURATE CORRECTON FACTOR WOULD BE SOMEWHAT DIFFICULT AND COSTLY AS IT MAY REQUIRE SEVERAL GENERATOR TESTING.
Yes
Yes
WE BELIEVE THAT FOUR POINTS IS SUBSTANTIAL INFORMATION FOR STRAIGHT LINE APPROXIMATION AS OVER-EXCITED (LAGGING) AND UNDER-EXCITED (LEADING) REACTIVE CAPABILITY AT RATED REAL POWER WOULD SOLELY BE A SUFFICIENT DATA FOR THIS PURPOSE.
Yes
Yes
Yes
THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Yes
THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Yes
Yes
No
No
No
No
Yes
Yes

No
No
Yes
IT WOULD BE EFFECTIVE IF SDT WOULD CONSIDER PROVIDING A DETAILED EXAMPLE OF DYNAMIC MODELS, GRAPHS, AND INFORMATION REQUIRED AS PART OF THIS STANDARD.
Yes
Yes
No
These devices are covered already under the VAR standards.
Yes
Yes
Yes
Yes
No
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
No
SCE&G believes that the Transmission Planner (TP) should receive this information, consistent with the current version of the standard.
Yes
The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
No
The verification of sisters units on an alternating basis should be allowed by the standard.
Yes
Yes
Yes
Yes

No
The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits.
No
No
Yes
If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners.
No
Yes
Yes
No
No
Yes
How are sister units to be handled? Do they all need to be tested individually. Also, are all the units counted individually when calculating the percent of units in the implementation schedule?
Yes
Yes
Yes
No
There seems to be a mistake on the Implementation Plan versus the Standard. The implementation plan states two years for the first 20% of applicable units and the standard states one year. Please clarify this inconsistency.
Yes
No
No
Yes
In regards to Measure 1 it should be clarified that only the latest coordination review will be needed for the first 5 years after the standard is implemented and only after 10 years will the entity be required to show both latest and prior evidence of compliance for 100 % of the applicable units. As stated, it looks like the standard would require the entity to verify the existence of coordination twice on 20% of the applicable units in the first year to show evidence of a latest and prior coordination for those units. If an entity were to be audited 3 years after the effective date of the standard, they would have to show coordination of 60% of the applicable units and should not be required to show a prior documented coordination since a 5 year interval would place the prior coordination possibly before the effective date of the standard. This would also apply in the situation of a newly built

applicable unit in which there would be no prior evidence available; only the latest.
Group
Westar Energy
Bo Jones
Yes
No
We agree data should be submitted to the Transmission Planner as written in the draft of the standard.
No
We believe data should be submitted to the Transmission Planner as written in the draft of the standard.
Yes
We propose that language be added to reference the Compliance Registry to ensure that as the Registry changes the appropriate applicability is followed.
Yes
Yes
No
We suggest that the SDT considering adding clarifying language around “as soon as a limit is encountered.” The current language is ambiguous.
Yes
Yes
We agree with the 50 MVA limit, however the standard does not currently address this limit.
Yes
Yes
Yes
The SPP Criteria requires that the testing period should be 15 minutes rather than the 1 hour listed in the standard.
No
No
No
We suggest for consistency with the other standards in this project that this standard also reference the limits used in the Compliance Registry.
Yes
Yes
No
No
No

Yes
Yes
In the standard the applicability for synchronous condensers is > 20 MVA for an individual unit. Additional language should be added to the standard to address the applicability for generating units/facilities.
Yes
Currently the requirements do not address variable static reactive resources located at asynchronous generating facilities as the question states. If the intent is for the standard to apply to variable static reactive resources located at asynchronous generating facilities, we propose language be added to the standard to address these resources. Yes, we do see a reliability need for including variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites. We propose that language be included to address the limit on the size of these types of facilities.
Yes
No
We would recommend the following implementation schedule: 20% - 2 years after regulatory approval 40% - 3 years after regulatory approval 60% - 4 years after regulatory approval 80% - 5 years after regulatory approval 100% - 6 years after regulatory approval
Yes
Examples for older units, where the information in the current examples are not readily available, could be included.
Yes
No
No
Group
IRC Standards Review Committee (joint comments)
Albert DiCaprio
No
It is not a matter of whether the requirements for real power verification is in one numbered standard and reactive verification is in another numbered standard, the important point is that the requirements be clear and separate. The posted standard fails that test by combining two requirements into one. It may look cleaner writing the two together; the problem is with the fact that such a format has the potential to needlessly risk getting some data when the other data is NOT available. If an asset owner could provide real data but not reactive data, the standard as written would incent the owner from providing either data (why waste a test when the owner knows it will be non-compliant anyway? By separating the two actions, the owner would be compliant with one and non-compliant with the other requirement – but the planner would have at least half the information.
No
MOD-025 is a requirement on owners to verify data, nowhere does the requirement state who the data goes to. Of course the owner is NOT the appropriate entity to send the data to since they are the ones that are responsible for generating the information. This standard has many issues related to who gets what data and why. There is no requirement to have the data in the first place. The standard would be better to require a planning entity to request the data that that entity needs to do its mandated functions. Once the planner asks for the data, then the owner can provide / verify the information being asked for. The SDT has rejected the comments that other standards already provide this information. The SDT has parsed the terms “capability” and “rating”. However, the NERC Glossary defines Rating as strictly a transmission line term, and the word capability is not defined. Capability does show up within other definitions related to Transfers and other transmission terms.

The SDT is asked to review their findings in light of the above, and in light of the FAC and TOP standards purposes. The TOP standard has developed the flexible approach of having an entity ask for the data it needs, and for the receiver of the request to provide the needed information. This approach eliminates the idea of a common requirement for all planners (whether or not they want the data elements in the posted Attachment 2). Our proposal is to have a requirement (if it does not already exist) mandating entities asks for what they want, and a separate requirement for the receivers to provide just that data. If the revised standard is written in that fashion than the new MOD-025 COULD replace the old MOD-024 because there would be no need to specify reactive data from real data, because the entities who are asking for the data will do that for you. Editorial: (1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”, we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs. (1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator’s real power capability to reflect a difference in ambient temperature. If anyone, it should be the Generator Owner. (2) Reporting the ambient temperature is unnecessary since it is only one of the many factors that could affect the real power output of a generator. Adjusting the real power capability for a different ambient temperature does not really provide a more accurate value, and can be misleading. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome, and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
No

See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
No
See comment to Q2. The planner should ask for the data that it needs to comply with NERC standards (nothing more and nothing less). There is no need for the requirement to get into the details. The Planning standards will force the Planner to ask for the data that it needs for its models. This approach limits the Planners from asking for data that they do not use in their Planning Models or that is not needed to comply with a NERC standard. This approach also allows the Planner to tailor its requests to the Models and technologies that it has and needs.
Yes
No
There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Yes
No
We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: “Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:” We interpret that the “IT” refers to the operational data. As such, we do not understand the “within 20% of the expected value”. Does it mean the generator’s real power output during the period from which operational data was collected must be within 20% of the generator’s declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity. As written, we are unable to comment on the acceptability of the 20%.
No
No
Yes
The proposed MOD-025-2 standard appears to violate many conventions, such as: o The use of Attachments for mandating requirements o The combinations of different actions in the same requirement o The mandating of specific formats

Does this SDT really believe a standard will "prevent" trippings due to mis-coordination?
Individual
Edward Cambridge
APS
being intentionally left blank (no answer to be provided)
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Group
Pepco Holdings Inc Affiliates
David Thorne
Yes
No
The standard in Sec B-R1.3 and R2.3 state to submit the data to the TP not the TO. The TP is the appropriate entity. However, the TOP and the TOP also have need of the data. Should dissemination to these entities be covered in the requirements also?
Yes

The ambient temp and correction factor should be provided to the TP with all the data as stated in Question 2.
Yes
Yes
However, based on the requirements and measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only apply to Transmission Owners that own synchronous condensers. If that is the case, Section A- 4.1.2 should be re-written as follows: “Transmission Owner that owns a synchronous condenser.” This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined.
Yes
Question 9 mentions that a threshold was proposed by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
Yes
“Staged” vs “operational” verification should be defined. In Attachment 1, are sections 2 and 5.2 consistent? That is should the % value be the same?
No
20% “appears” to be a large variance. The DT should explain the justification for 20%. 5% or 10% would seem more reasonable, especially for large units.
Yes
Should Attachment 1 Sec 5 be added to the standard list of requirements instead of part of the attachment? It appears that this section is more than just additional details on verification and reporting. In the project background information it is stated “..If regions have generating units that are connected at under 100 kV that are important to the reliability of the system due to some local consideration, then the region has the authority to require that those units be verified if they so choose.” This capability should be noted directly in the standard.
Yes
Yes
Question #2 mentions that a threshold was chosen by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
No
Question #3 indicated that as currently drafted the standard applies to variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites). This is either

specifically mentioned, or inferred, within the language of the June 15, 2011 Draft 2 standard. Regarding the question of a reliability need for including variable static reactive resources (e.g. static Var compensators) that are not located at generating sites in this standard, the answer is no. We see no need to make the standard applicable to Static Var Compensators (SVC's), whether they are located at generating sites, or remote from generating sites. An SVC is merely a thyristor switched / controlled capacitor or reactor. Maximum and minimum output is controlled by the firing controls to the thyristor, and is limited by the size of the installed shunt capacitor / reactor banks. When the thyristor is switched off there is no output. As the firing angle is increased toward the full on position the reactive output is increased until the full value of the shunt capacitor bank, or reactor bank, is reached. Protective devices and settings on the shunt capacitor bank and reactor bank within the SVC are typical of those employed on fixed banks. The control system merely provides a means to adjust the output between zero and full bank rating. As in the case of fixed banks, SVC protective devices are set assuming the full bank is in service. Therefore, if fixed shunt reactive banks are not subject to the standard, which they should not be, then SVC's should not be either. Synchronous machines, however, are a different story entirely. The quantity of reactive power produced by, or drawn into, the machine is a function of the machine field current. In an under-excited condition the unit may loose synchronism, or trip via loss of field protection, unless the voltage regulator (min. excitation limiter) is properly set and coordinated with the machine's capability and protective devices. Similarly, excessive Var output and / or terminal overvoltage caused by over-excitation of the field can result in equipment damage, or unit tripping, unless the voltage regulator is properly set and coordinated with the machine's capability and protective devices.
Yes
Yes
Yes
No
Yes
Based on the Requirements and Measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only apply to Transmission Owners that own synchronous condensers. If that is the case, Section A- 4.1.2 should be re-written as follows: "Transmission Owner that owns a synchronous condenser." This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined. Do the requirements in this new standard overlap or duplicative with PRC-001 R3 and R5?
Individual
Brad Haralson
Associated Electric Cooperative, Inc.
No
Real power verification is typically done using historical operating data because units commonly operate at full real power capability. Reactive power verification will most likely not be done using historical operating data. This standard implies that these verifications will be done at the same time. Applicable standards should allow for real and reactive verifications at different times.
No
The TP or PA seems more appropriate.
No
There is no simple correction factor that can be provided that will allow correction to other ambient temperatures. If necessary, a special request could be made to the GO/GOP for correction to another ambient temperature.
No

The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERCs current MOD-025 regional criteria). Independent verification of essentially identical units should not be required.
No
We don't agree that four points are needed for baseload units, since they are rarely expected to operate at or near Pmin. In addition to nuclear units, baseload units should be exempt from reactive capability verification at Pmin.
Yes
Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method.
Yes
We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR requirements when operating at low system load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
Yes
No
It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify more appropriate generating unit reactive capabilities that are needed to ensure that planning entities have accurate generator data when assessing BES reliability. MOD-025-2 should not focus solely upon operational testing to determine capabilities used for planning models, because experience has shown that testing does not provide appropriate reactive power capabilities. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed.
No
No
Yes
1) We agree with the stated purpose of this standard however we don't believe that this standard, as written, meets the intent related to reactive capabilities. We have already spent significant time, effort and money to perform reactive capability testing, and the test results provide little value toward establishing appropriate capabilities for planning purposes. Additionally, this testing puts our equipment and the BES at risk. It appears that this standard will make us repeat this effort with additional requirements for reactive capability testing at Pmin. 2) This requirement will require units

that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 3) The standard needs to allow the inclusion of engineering analysis to supplement or replace testing when appropriate (see comments to question #10). 4) Instead of the periodic requirements, there needs to be a change based validation requirement. If a plant is materially changed (such as significant equipment changes or performance degredation), there needs to be a new validation done. 5) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 6) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 7) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 8) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 9) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 10) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 11) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 12) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 13) Revise attachement 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 14) Note that the standard is only applicable to the GO/GOP, but needs involvement from the TO/TP/TOP to adequately complete a validation. Thus the standard needs to address the responsibilites of those entities for it to adequately address the issue of model validation. It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achiving the reliablity purpose intended. 15) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creats a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators.
No
Yes
Yes
No
No
Yes
1) Item 2.1.1 should be reworded: ".......model verification activities including the on-line RECORDED response compared to the MODEL'S SIMULATED response....." 2) It is anticipated that many GO/GOP's may not have industry experience with modeling concepts and model verification techniques. It may be beneficial to provide an appendix for reference that basically describes the anticipated mechanics of how the verification is performed. This may help provide consistency for the verification process.
Yes

Yes
Yes
Yes
Yes
Yes
No
No
Individual
Dan Roethemeyer
Dynegy Inc.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
No
Yes

Yes
No
No
Yes
1) In R2.1.1 it is not clear if the "recorded" response refers to the model response. Consider rewording this requirement to make clear the meaning of "recorded". 2.) Attachment 1 seems to give two options for periodicity of verifying the model frequency control functions for existing generators. One option is to record data for a BES frequency excursion during a ten year calendar period. A second option is to record such data after the ten year period if a suitable BES frequency excursion does not occur. Does this mean existing generators can wait indefinitely for a suitable frequency excursion to verify the model response?
Yes
Yes
Yes
No
Some of the requested data will reside in places not familiar to smaller entities and may require the use of consultants. The SDT may want to consider giving 2 years until the first 20% compliance level is reached because it will take time to set up a program.
Yes
No
No
Group
NERC System Protection and Control Subcommittee
Jonathan Sykes, Chair

Yes
No
The SPCS notes that the posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. The SPCS agrees with the 20 MVA threshold in the posted standard.
Yes
Devices such as Static Var Compensators and STATCOMs have equipment limitations, control systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser.
Yes
Yes
No
The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency.
Yes
No
Yes
Requirement R1: The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the generating unit, such as the list in Section G. Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions. Requirement R1, part 1.1.2: The word "check" is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as "Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment." Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project the Generator Owner should be required to verify coordination prior to placing the revised equipment or settings in-service. The SSSL derivation should consider the impact of system strength (e.g., strongest transmission line source out-of-service), generation saturation, and AVR status to assure an appropriately conservative limit. Implementing a UEL based on the steady-state stability limit may prevent under-excited operation, which would otherwise be stable and useful in managing system conditions (such as during system restoration activities or in lightly-loaded areas that need to sink reactive power to control voltage or synchronizing a generator to a long line). Where the Generator Owner and Transmission Owner are separate entities, there is difficulty for the Generator Owner to obtain system impedance information and keep it up to date as the transmission system may be re-configured during on-going operations; this information is necessary to represent the SSSL. The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with

controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.
Individual
Greg Campoli
New York Independent System Operator
Yes
No
In section B, R1.3, results are required to be submitted to the Transmission Planner. The NYISO agrees with R1.3.
No
Temperature correction shall be performed as required by the Transmission Operator. The NYISO requires ambient temperature data only for Real Power Tests for combined cycle, combustion, and turbine units.
Yes
No
There is no value to performing the lagging testing at minimum real power loading and leading test at maximum power. The testing requirement should be changed to two test points. One test for an hour to verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner; a second test to verify under-excited capability (leading) at the real power level specified by the Transmission Operator or the Transmission Planner.
Yes
No
Testing requirements for reactive capability at minimum real power output should be removed. These tests are of no value and lead to system limit concerns. The testing requirement should be changed to two test points. One test for an hour to verify over-excited (lagging) capability at the real power level specified by the Transmission Operator or the Transmission Planner. A second test to verify under-excited capability (leading) at the real power level specified by the Transmission Operator or the Transmission Planner.
Yes
No
100 MVA is a more appropriate limit.
Yes
No
What determines the expected value to be within 20% of?
No
In the NPCC region Directory 9 and 10 were written to meet the original obligations of MOD-024 and MOD-025. These directories are more specific or more stringent than MOD-025-2.
No
Yes
Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within its area. Additional NYISO Comments not addressed above for MOD-25-2 Under A. Introduction • Section 4 – Transmission Planner should be added under Functional Entities • Section 5.1.1 through 5.1.5 and 5.2.1 through

5.2.5 – These requirements should clarify that the Transmission owner requirement is for units that the Transmission owner owns and not for the generators in the Transmission Owners area. Under B. Requirements • Section 1.3 – The requirement should either be up to 225 days after the test or 60 days after the end of the test period. Attachment 1 – Verification of Generator Real and Reactive Power Capability • Section 1 – There should be some provision for allowing the verification results from small, electrically identical units at the same location to apply to other units in the group. • Section 2.1 – It is not practical to determine reactive power at rated gross Real Power capability. The requirement that ninety percent of wind turbines or photovoltaic inverters be online during verification of reactive power should be removed. • Section 2.2 – This verification is not needed. • Section 2.4 - Please clarify the definition of “limit”. • Section 3.2 - Please clarify the definition of “voltage schedule”. • Section 3.3 – This data is not needed. • Section 3.4 - Ambient air temperature is not needed for reactive power test results. It is only necessary for certain generators in Real Power tests (combined cycle, combustion and turbine). • Section 4 – The diagram is not needed. • Section 4.1 – For the NYISO, Real Power verifications are conservatively measured as Net output, so no auxiliary loads are required to be reported. Attachment 2 • Attachment 2 requires an unnecessary level of detail for “Data Type” to be recorded and collected; only gross MVAR, auxiliary reactive power and Net MW readings are required. • What is meant by “MVAR values were adjusted to rate generator voltage”?
Group
Southern Company
Antonio Grayson
Yes
No
The TP or the PC is the entity who needs the data, not the TO. R1.3 and R2.3 specifies that the TP be given this data.
No
The verification data is required by R1.3 and R2.3 to be given to the TP, not the TO. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
No
We believe that Section 4 Applicability for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. However, for plants with a gross aggregate nameplate rating ≥ 100, we question the need to perform verification for individual units as small as 20 MVA. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for verification of units as small as 20MVA needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their

criticality to the system seems to be inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1.
No
We agree that four points are sufficient to provide a straight line approximation over a unit's operating range. However, we strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." Paragraph 1321 of the FERC Order states, "…other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit’s real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit’s real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." These statements indicate the Commission is seeking further guidance from the industry. Based on this, we have the following recommendations. First, we believe 2.2 of Attachment 1 to the standard should exempt all base load units, not just nuclear units, from verification of reactive capability throughout the full MW range. There are other units the industry should be able to justify exempting based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) that prevent operation at minimum load. Second, we suggest that an evaluation be made on a small subset of units that could then be used to respond to the question raised by FERC. Our experience indicates that a unit will typically be capable of delivering or absorbing a comparable amount of reactive power to/from the grid at minimum load when compared to full load. The industry as a whole does not need to perform the verification at multiple points on 100% of the units to respond to an open question from FERC. Third, for units where verification of multiple points are needed, the analytical approach to verification we discuss in our responses to Questions 10, 11, and 14 serves this purpose very well.
Yes
Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Yes
We believe that the minimum load, it will be difficult for a unit to produce Vars because the system usually has minimum VAR output requirements from generators when the generators are operating at minimum load. Therfore, we believe verification of Vars out at minimum load will not provide the data that transmission planning is seeking and, therfore, this requirement is not necessary. See our response to Question 5 for additional discussion on verification at minimum load.
No
No
This MVA size does not agree with that found in the Applicability section 4.2.1 (20 MVA). As previously stated, we feel that the size of an individual unit that is significant in the Eastern Interconnection is 100 MVA.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). Reliance on data from testing or operations alone will result in understated reactive capabilities for planning purposes. To provide these alternative methods of establishing P&Q capabilities for each applicable facility, it is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or Attachment 3 (by engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is

noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
The "expected value" is not clearly identified, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the D curve for lagging Vars, we believe this is not a realistic expectation because operational data for most generating units does not approach 80% of the D curve value in normal operating conditions or even in staged testing based on our experience. A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed to be an alternative method for verifying the unit capability, the 20% tolerance given above is not needed. See our Comment 2 under Question 14 for additional discussion on the verification methods.
No
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be run for testing. Please consider a provision for excluding these requirements for units that do not regularly run unless verification using engineering analysis is allowed. 2) Each of the methods of verification proposed have merits and deficiencies. For staged testing, there exists the risk of tripping a unit during testing. System conditions which allow for the maximum reactive power output production/absorption are extreme system voltage conditions - precisely where it is undesirable to perform such testing or trip a unit. Staged testing or verification using operational data during normal system voltage conditions will result in reactive limits constrainted by system conditions (not representative of the actual unit capabilities for extreme voltage conditions when the reserve Var capabilities are needed most). Staged testing may, however, reveal unknown thermal or mechanical problems which, while are good to know, are maintenance related and are not the primary objective of the standard which is verification of reactive capability for use in planning models (Long Term Planning Horizon). But, if system constraints during staged testing do not permit a unit to reach the reactive limits the unit could reach during extreme system votlage conditions, one could argue the results of the test are inconclusive in terms of meeting the reliability objective of the standard. Our experience has shown that unit reactive limits for extreme voltage conditions (when the reserve Var capabilities are needed most) can best be determined using engineering analysis. It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC Regional Criteria for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The test interval and new unit test requirement described in Attachment 1, part 5 should be included in the main standard requirement section rather than in the staged test details. However, we believe re-verification every 5 years is too frequent. We agree that re-verification is appropriate for significant changes that impact the real or reactive capabilty by more than 10%, but we question the six month criteria. For the Long Term Planning Horizon, one year would be more appropriate. 4) In R1.2 and R2.2 the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changin R1.2 anf R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to

read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 11) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP (> 30 days late).
No
1) We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action. 2) It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy.
Yes
Yes
No
No
Yes
1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don't match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) In Requirement R4, it is unclear how an entity could revise model data without performing a model verification - (the requirement is written to either revise model data or plan to perform model verification) 8) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. Those items that need correcting include: 8a) The "Facility" column entries need to better describe the conditions that are being detailed in the "Condition" column. Can some additional words better describe the each row? [for example, the row 2 could have the title 1-existing unit, no sister unit exceptions; row 3 could have the title 2-existing unit, sister unit exception applies, etc.] 8b) The use of "exceptions" in the Draft 1, row 2 is not defined and it is unclear what exceptions may apply. 8c) Can the third AND element of the Condition described in row 2 be written more simply by beginning "While the unit is operating in a frequency responsive mode and is subjected to at least one BES frequency excursion as specified in Criteria 1 above." This change could be used in multiple entries of

this table to simply the reading and understanding. 8d) For row 3 (with exceptions row), we suggest eliminating the requirement for the same physical location being true for allow "sisterhood" - an entity is likely to own multiple units at different physical locations which are identical. 8e) Row 5 contains "new excitation control system equipment" - shouldn't this be "new governor/load control equipment"? 8f) Row 7 contains "Excitation control system model" rather than "Gov/Load control model"
Yes
No
We feel that this standard is not applicable for solar facilities. For other facilities, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit, 15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units ≤ 75MVA may be identified by a transmission entity as critical for BES reliability. Thus, the standard could include requirements applicable to such units where identified by a tranmission entity as critical for BES reliability.
Yes
Yes
Yes
No
Only the last two documentation sets are needed to prove the intervals are being met. ALL previous sets are not necessary. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
No
Yes
1) The last sentence of Measure M1 is not needed. There is no need to require evidence of the change implemetation, only coordination verification is needed. The requirement for documentation of change identification or implementation is not part of Requirement R1. 2) In several places in the posting documents there is a descrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 3) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 4) Section 5.2.5 is missing from effective date in the draft standard.
Individual
Samuel Reed
Tri-State Generation and Transmission, In.
Yes
Yes
The standard also calls for the data to be submitted to the Transmission Planner, so this question seems ambiguous.
No

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
No
Yes
Yes
No
No
No
Yes
Yes
The standard seems to indicate 20mva instead of the stated 50mva.
No
The standard name indicates it applies to generating sites.
Yes
Yes
Yes
Yes

No
No
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Combination of closely related standards simplifies compliance program development, and is welcome.
No
Not all Transmission Owners have a complete system view of the BES, let alone modeling software. The standard as written specifies the Transmission Planner, and so the question appears to be in error. Following the purpose statement of the standard, the Planning Coordinator (formerly Planning Authority) might also need the data along with the Transmission Planner. To further complicate the matter, in WECC CUG meetings it has been brought up that entities are experiencing difficulty in identifying their Planning Coordinator and Transmission Planner. Such entities have been rebuffed when approaching the obvious candidates. Therefore, Cowlitz suggests that a mechanism must be devised such that Generator Owners will not left in a compliance quandary in their endeavors to identify the appropriate planner(s).
Yes
As long as correction factors may be documented from normal run history, this would not be burdensome to produce. As currently written, MOD-0025-2 appears to allow the Generator Owner to make a judgment call on whether ambient air temperature plays a significant role in generation capacity. If this is the case, then the report form should have a specific question: Is ambient air temperature correction factor applicable? ______ If yes, include in remarks below correction factors for different temperatures. Also, water coolant temperature may play a greater role. A quick passing hot or cool day during testing may not have any effect on the water coolant temperature. Where water temperature has a greater impact on capability, seasonal trends may be of greater significance. Finally, there is no criterion stipulated to define when ambient temperature correction factors are significant and should be provided. Cowlitz suggests that ambient temperature should only be considered significant if it affects Real or Reactive Power capability more than 10% between the lowest and highest expected ambient temperature extremes.
No
The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Cowlitz is not convinced that the Standard be applicable to the compliance registry of Generator Owners. For example, an entity owning a single small 500 KVA generation plant currently is exempt from registration; however it may own a transmission protection system protecting a BES element from a fault originating on the high side of the step up transformer. Therefore it should register as it is material to the reliability of the bulk power system. From the extensive reference of 20 MVA and 75 MVA in the Standard from the Compliance Registry Criteria, it appears that the SDT would not see a need for the 500 KVA generation plant to verify its capability. Further, pointing to the Compliance Registry Criteria’s generator MVA name plate ratings is also questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. After reviewing the Field Test Results, Cowlitz finds that WECC set the line at 10 MVA and SERC recommended 75 MVA with no substantiating arguments. Also noted in the Field Test Results was a

problem in getting the dynamic models to return data results that agreed with actual events. With the Field Test Results dated in 2007, Cowlitz is unsure on the current accuracy of dynamic model predictions. However, if models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Looking over the data requirements of MOD-25, Cowlitz can see that there will be considerable consultant cost – $25,000 – to comply. Using the Compliance Registry Criteria for applicability is not acceptable. Unwarranted compliance efforts will reduce overall reliability results. Cowlitz recommends the SDT consult with Planning Coordinators (Planning Authorities) and Transmission Planners on the current status of modeling accuracy and request documentation for generation that can be ignored. Also, it may be permissible for smaller generation to simply report seasonal historical Real and Reactive Power output.
No
Cowlitz answers “no” in that the question does not address if the data is truly going to be used. The SDT should confer with Transmission Planners requesting specifically how they will implement such data and if it will result in better modeling results. Data collection that will not be used is wasted compliance effort. FERC also seems to be confused as to the purpose of the Standard when it states “[t]he capability of generators to produce reactive power is essential for real-time analysis” rather than system modeling and planning. Based on this, should the reactive capability data also be sent to the Balancing Authority? If the SDT has technical foundation to refute FERC’s directive then it should be communicated. The Standard can be written as FERC demands, but with a recommendation that the requirement be removed.
No
Cowlitz suggests that “rated” be replaced with “normal expected maximum” in requirement 2.1 and “maximum” in requirement 2.3; although the footnote makes the intent clear, there is no need to complicate the reading of the Attachment and effectively redefine the normal understanding of the word rating. As far as running the test at least one hour, this commenter is not sure how quickly a unit achieves thermal stability. Again, Cowlitz questions if the data will be used and its actual contribution to improved modeling and future planning.
No
Cowlitz at this time has insufficient information to formulate an opinion, but at the same time is skeptical of the reliability benefit being great enough to justify the cost of obtaining this data.
Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Cowlitz does not own such equipment and therefore must defer to those that do. Cowlitz will consider the comments of others in the future.
Yes
Operational data will always be the preferred method of obtaining verification; however Cowlitz can’t see how this would be possible for obtaining the reactive capabilities as prescribed. This will require costly and burdensome staged testing.
Yes
No
No
Yes
As already stated, Cowlitz questions the reliability benefit of the extensive reactive capability requirements and is currently consulting with Transmission Planners if such extensive data will actually be beneficial in their modeling efforts. It may be better to require data that must be verified though staged testing only after request by the Transmission Planner with a reasonable time frame to obtain the data.
No
Yes

Yes
No
No
No
Cowlitz has no opinion.
No
The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Using the Compliance Registry Criteria’s generator MVA name plate ratings to assign applicability of the Standard is questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. If models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Further, the unit versus plant MVA criteria is illogical. If the BES can withstand the loss of a 75 MVA plant, then logically it will withstand the loss of a 20 MVA unit. Cowlitz believes that after the appropriate study is completed, the applicability line should be somewhere in the range of a verified nominal plant or unit output of 100 to 200 MVA. Last of all, applicability should be assigned to BES generation when it has been defined.
Yes
But not at the 20/75 MVA name plate criteria. First the applicability should be tied to expected maximum MVA output. Second, the MVA basis should be established from a modeling study. Ultimately, the applicability should only include plants that are members of the BES once this has been defined.
Yes
Yes
For Cowlitz, this would be acceptable. However, Cowlitz only owns a few generation plants. We must defer to those who own many plants.
Yes
Cowlitz needs to confer with its consultant to form a more informed opinion. However, it appears to be reasonable.
Yes
No
Yes
Cowlitz understands the difficulty the SDT is under. Although the base line of applicability is in question, this Standard is justifiable and will not present too great a burden to comply with.
Individual
Alice Ireland
Xcel Energy

Yes
Yes
No
Yes
Yes
No
Southwestern Power Pool testing criteria specifies a 15 minute hold point and WECC requires holding until the temperatures are stable, which has always been less than one hour. We believe one hour is excessively long, and instead recommend a 15 minute verification time.
Yes
Yes
Yes
There is a discrepancy between this question and the size limit in the draft standard (20 MVA). We believe 50 MVA is the better value.
Yes
Yes
No
No
Yes
It is not clear in the standard if a separate load flow report (Attachment 1) is required for each point of verification, or only for the maximum load, maximum lagging reactive point. Please clarify in the standard.
No
Yes
Yes
condensers have no effect on system frequency, they are there for voltage support. We agree they should not be in MOD-027-1.
No
No
No
Yes
Yes

There is a discrepancy between the question and the 20 MVA size limit for synchronous condensers in the draft standard. We believe 50 MVA is the better value.
No
These units are not tested under the proposed MOD-025-2, so should not be included in PRC-019-1.
Yes
Yes
Yes
Yes
No
No
Group
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)
Carol Gerou
Yes
No
The standard states that the data be submitted to the Transmission Planner and we agree with that approach.
No
We recommend that in Item 3.4 of Attachment 1 the wording be changed from “to allow the Transmission Owner” to “to allow the Transmission Planner”. We support the position that the ambient temperature at the end of the verification period and the correction factor should be provided to the Transmission Planner so that the Transmission Planner can adjust the verification results to the ambient temperature that is appropriate for its system planning assessments.
No
There may be generating units or facilities that are included or excluded as BES elements either by the latest BES definition or the latest BES exception procedure that differ from 4.2.1 and 4.2.2. So we recommend adding anItem 4.2.4 to the Applicability section that states, “Generating facility, generating unit or synchronous condenser that are designated as a BES Element according to the BES definition or BES exception procedure.”
Yes
Yes
Yes
Yes
Yes
Yes
Yes

No
No
Yes
Please consider the following comments: Attachment 1, Item 2 – Add the adjective “gross” to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. Attachment 1, Item 2 – Modify the wording of “with all auxiliary equipment needed for expected normal operation” to “with all auxiliary and voltage regulation equipment, such as reactive power compensation, needed for expected normal operation and voltage regulation” to assure that any reactive power compensation equipment (e.g. capacitor banks, SVCs, STATCOMs) are not overlooked and omitted from the verification data. This added text is particularly needed for wind generation situations. Attachment 1, Item 2 – We would prefer the acceptable verification with operational data to be 10%, rather than 20%. Attachment 1, Item 2 – Expand the text of “expected value” to “expected maximum gross Real and Reactive Power Generator capability values” to add more clarity. Attachment 1, Item 2.1 – Add the adjective “gross” to the Real Power and Reactive Power reference for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. Attachment 1, Item 2.1 – Replace the wording “at rated gross Real Power capability” with “at the generating unit’s normal expected maximum Real Power capability” and drop the footnote reference. Attachment 1, Item 2.2 – Add the adjective “gross” to the Real Power and Reactive Power references for added clarity and to assure awareness that the verification is for “gross”, rather than “net” values. Attachment 1, Item 2.4 – We think that both “2.1 and 2.2” should be referenced for the over-excited data. If this is incorrect, then please explain why 2.1 should be omitted. Attachment 1, Item 2.6 – Add an Item 2.6 of “Record the generator step up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer”. This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements were taken. We are aware that this oversight has already occurred several times. [Add Point “F” (pointing to the generator step up transformer) to the Verification Information Reporting Form in Attachment 2 to accommodate and remind the Generator Owner or Transmission Owner to record these losses, when it is needed.] Attachment 1, Item 3.4 – Correct the functional entity reference from “Transmission Owner” to “Transmission Planner”. Revise the wording to allow the Generator Owner or Transmission Owner to report, “The ambient air temperature and/or ambient water temperature at the end of the verification period”. [Require that the ‘basis’ ambient air temperature and/or ambient water temperature associated with the reported gross generator Real Power capabilities be stated on the Verification Information Reporting Form along with a correction factor if any, to allow the Transmission Planner to correct the Real Power capability to different ambient temperatures, if needed.] Attachment 1, Item 3.7 – Add an Item 3.7 of “The GSU transformer losses if the verification measurements were taken from the high side of the GSU transformer.” This addition will help avoid the omission of the GSU transformer reactive power losses when calculating the gross generation power capabilities when high side measurements are taken”. Attachment 1, Item 5.3 – Add revise the wording, “within one year of their commercial operation” to “within one year of their commercial operation or as scheduled by the applicable Transmission Planner” to allow the exception of an earlier or later due date when it may be appropriate and agreed to be the affected Transmission Planner. Attachment 2, Item A – Add a note that the individual unit values should be reported separately whenever the verification measurements were taken at the individual unit. In most cases, the individual units are modeled separately (including compound units) in the power flow cases and the loss of individual units are simulated in system planning assessments. So, if the verification data was collected in a manner that would allow individual unit power capability verification, then the reporting form should not direct the Generator Owner or Transmission Owner to mask this information. Attachment 2, Item F – As noted above, add a Point “F” (pointing to the generator step up transformer) to the Verification Information Reporting Form to refer to the GSU transformer losses. Also add a Point “F” row to the data table with entries that indicate to provide the GSU transformer MW and MVAR losses when the verification data was based on measurements that were taken from the high side of the GSU transformer. Otherwise, GOs and TOs that base verification values on measurements from the high side of the GSU transformer may forget to make the proper correction when they calculate the gross values for Point “A”, as others have historically done. The scope of this

standard does not include the verification of high voltage power flow controllers that are connected to the transmission system at 100 kV or above. We propose that a Standard Authorization Request (SAR) be created to address the power capability verification gap that is not being filled with this standard. The test form has remarks space for reactive limit constraints but not for real power constraints. Attachment 1 , #2, the use of the word “all” auxiliary equipment is unnecessary and is over reaching, the Requirement is for expected normal operation. Recommend deleting “all” from this sentence. Attachment 1, # 2.1, should the SDT give an alternate threshold if “90%” could not be achieved during the testing window?
No
Yes
We agree with this proposal as being in line with our overall concern that model verification requirements should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
No
It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.
No
No
Yes
Please consider the following comments: Footnote 2 - Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value”, since historically some have asked how this factor is defined and calculated”. Requirement R3, bullet 2 – Append wording like, “such as a model is unusable by the Transmission Planner, dubious model type, abnormal model parameter values, and unusual simulation results” to the text, “technical concerns with the verification documentation”. Attachment 1, Row 6 (New or Existing Generator Unit) –Replace “Excitation control system model” with “Turbine/governor and load control or active/frequency control system model”. Comments: We have a number of questions and concerns as follows: • While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. • If a simulation study results in response characteristics that does not match an on-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Yes
Yes

No
Yes
No
It appears that Item 5.2.5 in the Applicability section is missing. We propose adding, “5.2.5 By the first day of the first Calendar quarter, five calendar years following Board of Trustee approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units”.
Yes
Yes
No
Yes
Consider adding a note to Attachment 1, which states that the type of D curve should be specified (i.e. based on the data reported per the MOD-010 standard, the data reported per the MOD-025-2 standard, or some other basis).
Individual
Mace Hunter
Lakeland Electric
Yes
Yes
Yes
Yes
Under the section B. requirements R1, 1.1; it refers us to “attachment - 1” . Under attachment – 1, item 2 – 2.1 it states the following: • Perform verification of real and reactive power capability of all generating units at maximum over excited (lagging) and under-excited (leading) reactive capability at gross real power capability. We would like to propose adding “or to the documented limiting factor of the equipment (generator, voltage regulator, transformer, transmission etc.)”. We want to avoid having to test to the min and max of the capability curve if there is some other limiting factor we can document.

Group
SPP Reliability Standards Development Team
Jonathan Hayes
Yes
No
Is there a typo in the question? Should Transmission Owner be Transmission Planner? If not then adding the Transmission Owner as an intermediate step before submitting data to the Transmission Planner isn't needed.
Yes
We feel that the entity should be the Transmission Planner, but there is a need for the Generator Owner to provide an adjustment factor. The standard should address the temperature to bring the data to and then the Generator Owner could provide the factor to adjust the data. The standard also needs to address the fact that the temperature will not be a single set number and will vary depending on the season and geographic location.
Yes
If the intent is that the team wants to follow the Compliance Registry then we would ask that there be direct language reference to the Registry. If this isn't done and the Registry changes as worded now the standard would be static to the numbers given. This team needs to get plugged into the BES DEF standard drafting team as there are discussions being held currently that could change the Registry criteria.
No
This is a non linear curve. Is the reason for using the 4 point method all that would fit into the model? We also have the concern that isn't addressed here and it is if the unit can't be tested at the time due to system conditions then you must wait until the system is able. We feel that the points should reflect what is usable.
No
Currently SPP has criteria that the testing period should be 15 minutes rather than the listed 1 hour. We have found that this time period is adequate.
No
We would request that the time be a few minutes to make sure after a settling period that it was a limit that was encountered.
Yes
Yes
We agree with the 50 MVA limit but would request that it be included in the actual standard.
Yes
No
We feel that 20% is too great a buffer for this data and would suggest that the number reflect a

buffer of 10% or less. We feel like having a buffer that is too high would cause entities to not use testing verification and would use the operational data verification. We also feel that this verification should be as accurate as possible to reflect the system in planning.
Yes
If the testing time is 1 hour as written then we have a variance of the SPP criteria of 15 minutes, but if the team decides to change that time limit then we wouldn't and our answer would change to no.
No
Yes
VSLS for R2 there is an extra applicable in the chart. Would suggest removing.
No
By setting the MVA rating at 100MVA in section 4.2.1 for single units aren't you excluding units? It is then mentioned in the bullet below that units below 20MVA are included but as an aggregate if the site is over 100MVA. We aren't clear how this is expanding the standard. The other standards in this group refer to the limits used in the Compliance Registry. Should this be consistent with those?
Yes
We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
No
No
Yes
In the VSLS for R2 there is a "no" that needs to be deleted. In VSLS for R2 and R4 there is a footnote referenced on page 2 of the draft standard so it shouldn't be included here as well.
Yes
Yes
This question refers to the applicability of the standard yet doesn't reflect the wording in this question. In the standard the applicability for synchronous condensers is 20 MVA due to it being lumped with single units. This needs to be broken out in the applicability section of the standard.
Yes
We weren't able to locate the variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites) within the standard as the question suggests. We feel like variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites should have been included but would request that the team provide a limit on the size of these types of facilities. Our team isn't sure what a cutoff number would be, but would ask that the drafting team investigate this issue to come up with an appropriate number.
Yes
No
The team would like to move out the initial 20% to 2 years and add a year to the following phases as well i.e 40% 3 years 60% 4 years etc. 5.2.5 seems to be missing from the standard which doesn't include a bullet for 100% for those who need Board approval.
Yes
While the team agrees with this evidence, some of the older units in the system may not have this information readily available.
Yes
For new units or units that haven't changed you would not have prior data to provide. The drafting team may need to think about rewording to address this issue.

No
Yes
It seems there is room for clean up in the posted standard.
Individual
John Bee
Exelon
No
The requirements of MOD-024-1 and MOD-025-1 should remain separate. The testing periodicities and the reporting requirements for both of the existing Standards are different. In addition, the SDT needs to closely coordinate with existing testing and reporting requirements 1) Regional requirements and reporting criteria (e.g., MOD-024-RFC-01.1) and 2) Transmission Planner requirements (e.g., PJM has separate reporting criteria). If the SDT continues to push for a combined Standard, then consideration must be given to splitting out the requirements (i.e., separate Attachments) for Real and Reactive Testing.
No
The Transmission Planner should be the appropriate entity to receive this data.
No
The Standard needs to address correction factors for "ambient conditions" instead of "air temperature." Specifically, large generating units are typically water cooled and therefore the correction factor should be revised as such. In addition, as stated in the response to question 2 above, the Transmission Planner should be the appropriate entity instead of the Transmission Owner.
Yes
No
Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability 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 NRC operating license. Suggest the following revision to Attachment 1 as follows: 2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.
Yes
The time of one hour as a minimum is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the generator reactive capability curve (RCC).
Yes
Recording the test data as soon as a limit is encountered is reasonable; however, the reactive capability may not able to be tested at the rated Real Power Capability. It may not be feasible to perform both Real and Reactive tests at the same time. Considerations must be given for the reactive limits given by the plant specific generator reactive capability curve (RCC) at the attainable real power output. Currently Attachment 1 states that nuclear units are excluded from performing Reactive Power verification at minimum Real Power output. This exclusion must be extended to include a statement that nuclear units are not required to perform under-excited (leading) reactive capability verification testing. Nuclear units do not perform under-excited (leading) reactive capability 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 NRC operating license. Suggest the following revision to Attachment 1

as follows: 2.2 Verify Reactive Power of all generating units other than wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. Nuclear Units are not required to perform under-excited (leading) reactive capability verification testing or Reactive Power verification at minimum Real Power output.
Yes
Yes
Yes
Yes
Yes
It is strongly suggested that the SDT review each existing Generator Real and Reactive Power Capability Regional Standard (or other guidance) currently in place for best practices and potential conflicts. As stated in responses to questions 5, 7, 13, and 14 nuclear units do not perform under-excited (leading) reactive capability 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 NRC operating license. Exelon Nuclear is a member of and has 17 nuclear units in two Regions (ReliabilityFirst and SERC). RFC Regional Standard MOD-025-RFC-01, "Verification and Data Reporting of Generator Gross and Net Reactive Power Capability," currently has a specific exclusion that "Under-excited (leading) Reactive Power capability verification is not required of nuclear units." SERC Regional Criteria, "Verification of Generator Real and Reactive Power Capability," has the following statement regarding nuclear units, "(t)he capabilities of nuclear units will be determined taking into consideration the fuel management program of the unit and any restrictions imposed by regulatory agencies.
Yes
Nuclear units do not perform under-excited (leading) reactive capability 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 NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements.
Yes
Nuclear units do not perform under-excited (leading) reactive capability 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 NRC operating license. Performance of reactive capability tests cannot challenge nuclear plant NRC licensee Technical Specification voltage limit requirements. Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities. Suggest that all exceptions to test performance criteria be pulled forward into body of the Standard. Additional comments for MOD-025-2 Attachment 1 • Step 2.3 – remove reference to "rated real power" - the reactive power test is conducted as a stand alone test using the attainable real power (which is generally governed by ambient conditions at the time of the test). • Step 2.4 – remove reference to "over-excited reactive capability" – the over-excited test is conducted for a minimum of 1 hour • Step 3.4 – remove reference to "correction factor: - this applies to correcting MW as part of the MOD-024 test. Reactive power is tested at the attainable MWe.
Yes
No

Yes
The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units…".
Yes
Exelon strongly suggests that the SDT coordinate this revised Standard with the Nuclear Regulatory Commission (NRC) to preclude any challenges to the licensing basis of any of the nuclear generating facilities. The proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. As detailed in a memorandum from Jesus (Nano) Sierrra (FERC) to John Odom (ERAG Management Committee Chair), "Follow-up on the Provision of Primary Frequency Response by Nuclear Units in the ERAG-MMWG Dynamic Models," dated April 27, 2011, most all generating units do not respond to frequency deviations; however, there are some nuclear unit designs that do have limited response to under frequency conditions. It is important to note that even if a nuclear unit' s governor design does have limited response to grid frequency deviations, the nuclear unit is administratively restricted by their respective NRC operating license requirements to 100% thermal power. It is not clear from the proposed Standard MOD-027-1 or the Implementation Plan the SDT intended implementation timeline for the first verification period. That is, when must Requirement R2 be completed for the first 25% of the Generator Owner's applicable units? The second 25%? Etc. It is confusing when considering the wording in Section A.5, "Effective Date:" combined with the wording in Attachment 1, Criteria 2 of the Standard. In addition, the Implementation Plan does not provide any further guidance. Is the intent that the staggered percentage implementation provides the start time for the generating units to complete R2 within a following ten year period? This would allow the applicable units to modify/install recording equipment and then set T=0 to then start the ten year staggered verification period. OR Is the intent to short cycle the initial verification period during implementation based on the percentage of units and then set up a ten year staggered verification period thereafter?
No
The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (top of page 7) states "(F)or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "… assuming normal AVR control loop and system steady state operating conditions. Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic"). The SDT needs to allow for automatic mode for AVR to accommodate those Generators that have redundant automatic channels as is the case for newer digital AVRs. This will allow the owner to use AVRs automatic mode when plotting SSSL.
No
Exelon does not see a reliability need to include static reactive resources in PRC-019. The standard as written is applicable to voltage regulating controls and limit functions with generator capabilities and protection system settings which is generator specific. Adding static reactive resources would require unnecessary additional guidance to be included in the standard. The maintenance and coordination of relays related to static reactive resources is currently covered in PRC-005 and modeling and studies are included in the MOD standard.
Yes
No
There is a conflict with the implementation periods stated within the body of Standard PRC-019-1 and the associated Implementation Plan. PRC-019-1 Section 5 Effective Date Step 5.1.1 states "(b)y the first day of the first calendar quarter, one year following applicable regulatory approval … " [emphasis

added]; however, the Implementation Plan states the Effective Date is "(t)he first day of the first calendar quarter two years following applicable regulatory approval ... " [emphasis added]. Exelon requests that the implementation period be 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage.
No
In addition to the methodology listed, a provision should be allowed to use an alternative acceptable methodology that meets the intent of the Standard such as a methodology that uses impedance locus for loss of field for settings for the loss of field relays. Attachment G second formula is incorrect and should be corrected as follows: R = V2 g/2*(1/Xs+1/Xd) (Divide by 2)
Yes
No
No
Group
Tennessee Valley Authority GO
David Thompson
Yes
No
The TP or the PC (PA) is the entity who will use the data. R1.3 and R2.3 specifies that the TP be given this data.
No
Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to be the same.
No
We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC’s current MOD-025 procedure). Independent verification of essentialy identical units should not be required.
No
Although we agree that four points are sufficient to provide a straight line approximation over a unit's operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification, discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit’s real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit’s real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, We do not believe that verification for

leading capability should be required where operational practices preclude operation in a leading mode.
Yes
Yes
But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available.
No
It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate. It is noteworthy that the original NERC Board Approved version of this standard states in

requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5-year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used. We suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results. Consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and believe this requirement should allow for additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) Revise attachement 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 11) It is noted that MOD-11, which is supposed to clarify modeling data requirements, has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achiving the reliablity purpose intended. 12) This standard establishes a periodic generator testing regime which, when implemented on a large number if generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach for most generators. Targeted testing can have application on a limited basis.
No
Yes
Yes
Yes
We think it is possible that the unit rating which is critical to the BES may vary from region to region.
No
Yes
It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency excursion. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. 2)
Yes
Yes
No
Yes

Yes
Yes
Yes
No
Yes
We recommend that the minimum unit rating to be applicable to this standard should be 75 MVA, and the aggregate plant size to be applicable should be 100 MVA.
Group
Luminant Power
David Youngblood
Yes
No
This is not applicable in the ERCOT region. Data should be submitted to TOP and BA. They are currently responsible to utilizing the information for grid reliability.
No
Luminant agrees that ambient test temperature and temperature correction information should be submitted to the appropriate entities. In ERCOT, this would be TOP and BA.
Yes
No
Luminant proposes the following: 1. At High Load - Maximum overexcitation and under-excitation testing shall be conducted at a minimum of 95% of real power output capability and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 2. At Low Load - Maximum overexcitation and under-excitation testing shall be conducted in the output range between minimum stable load and minimum stable load plus 30%, and achieve 90% or greater MVAR output based on the reactive capability curve or as limited by system conditions. 3. Lead and lag tests can conducted independently.
Yes
Yes
See Luminant comments to Question #5 regarding operating ranges for testing.
Yes
Yes
Yes
No
No
No

Yes
Yes
No
No
No
Yes
Yes
No
Yes
Yes
In requirement R5.2 – there should be a sub-requirement R5.2.5 for 100% compliance at five calendar years?
No
This item needs to coordinate with PRC-001 (System protection Coordination) and the future PRC-023-1 (generator loadability) standard currently under development. Section G indicates a distance relay (21) but does not indicate any timers that would be coordinated with the transmission provider. Propose removing this protective relay from Attachment 2.
No
Once coordination is completed, the retention shall be until the unit is retired or a system change has occurred, plus any coordination document that was in effect during the current audit cycle.
No
No
Group
SERC Planning Standards Subcommittee
Charles W. Long
Yes
No
TThe PSS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
Yes
The Transmission Planner should be allowed to require that the Generator Owner provide an adjusted real power value (instead of an adjustment factor) based on different ambient temperature(s).
No
The use of sisters units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability. However, the standard should apply to designated blackstart units included in a system restoration plan, regardless of size.
Yes

Yes
No
We recommend a limit of 20 MVA since these may be in remote areas where reactive capability is critical.
Yes
No
The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
If the demonstrated value is less than the expected value, then the GO's should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. 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
Michael Goggin
American Wind Energy Association
Yes
Yes
No

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
No
Yes
Yes
No
No
No
Yes
Yes
No
Yes
Yes
Yes
Yes

No
No
Individual
Keith Morisette
Tacoma Power
Yes
Yes
No
Tacoma Power is not aware of any industry accepted standard air ambient real power correction factor for hydro units.
No
1) Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. 2) Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity.
Yes
No
Depending on the size of the unit and location in the transmission system operating the unit at full rated reactive capability with normal steady state transmission voltages may subject the plant and transmission system to a sustained overvoltage. The over-excitation limit should be verified in the same way the under-excitation limit is verified.
Yes
None
None
Yes
None
Yes
None
No
None
No
None
No
None
No
None
Yes
None
No
None

No
None
No
Yes
None
No
Even if the variable devices or their impact is well defined, such as ”Devices within 2 buses and that can affect the transmission system voltage plus or minus 5% or greater”, including this requirement for variable static reactive sources could involve a wide scope of devices and potentially many owners and operators for very little improvement in reliability.
Yes
None
Yes
None
Yes
None
Yes
None
No
None
None
Group
Idaho Power-Power Production
Tim Brown
Yes
Yes
Yes
No
No
Yes
Consistancy with the compliance registry and the BES definition is important.
No
No, we believe that the four points are not adequate to describe a unit’s capability. FAC-008 and FAC-009 require us to have a normal and emergency rating and the WECC validation policy requires the verification of the unit’s capability. Is this standard intended to replace those standards/policies? If so it was not clear in the project documentation. If not, we believe this standard to be redundant to our existing policies and procedures here in WECC.
No
No, if this is intended to verify an emergency reactive capability we believe 15 minutes is sufficient. If this is intended to verify a normal reactive capability then 1 hour is reasonable.
Yes
Yes
Yes
No

What is the technical basis for the 20%? It seems high.
No
No
No conflict, but as stated before, it seems to be redundant with FAC-008, FAC-009 and the existing WECC validation policy.
Yes
1. The language in the Applicability Section 4.2.1, implies that the standard applies to only synchronous condensers in generating facilities. Please clarify. 2. As stated before, we believe that FAC-008 and FAC-009 specify our generator have an normal and emergency rating. The standards should use similar language in requiring validation of capability. However, our regional policy required by MOD-010, specifies validation of the generator reactive capability, thus we believe this standard is redundant and not needed. That is unless MOD-010 is going to be retired. 3. Note 1 in Attachment 1 states that the data point may not match the manufacturer capability curve or the verified values for the MOD-010 standard. We question what the point of this standard is if not to validate. Note 1 mentions other items that might be discovered during the validation required by this standard, but we believe those benefits are achieved by our existing validation policy.
Yes
We believe Black Start units, regardless of size, should be considered in this standard.
No
WECC has an existing model validation policy that is well defined and established. This project documentation does not specifically state that MOD-012 and MOD-013 would be retired. If not, this policy would be redundant with the existing WECC policy.
Yes
Yes
Yes
Yes
No
We believe that the tutorial like language in Section G is not appropriate for a standard. There is an abundance of material available describing the coordination of generator protection equipment, such as textbooks, IEEE tutorials and even NERC tutorials. We believe referencing the documents could be appropriate and helpful. Even though the diagrams are listed as examples, we believe they might be interpreted a recipe to be followed.
Yes
No
No
Group
Santee Cooper
Terry L. Blackwell

Yes
Yes
No
Recommend changing Section 4.2 Facilities to match Section 4.2 Facilities as it is written in MOD-026-1 and MOD-027-1 below: 4.2. Facilities For the purpose of this standard, the following Facilities are considered, “applicable units.” Units or plants with an average capacity2factor greater than 5% over the last three calendar years that meet the following: 4.2.1 Generating units connected to the Eastern or Quebec Interconnections with the following characteristics: • Each generating unit with a gross nameplate rating greater than 100 MVA, connected at the point of interconnection3at greater than 100 kV. • For each plant with a gross aggregate nameplate rating greater than 100 MVA, connected at the same point of interconnection at greater than 100 kV: o Each unit with a gross nameplate rating greater than 20 MVA; and o The remainder of the plant as an aggregate. There should also be some allowance for Units which are nearly identical and therefore model the same.
No
The current SERC Regional Criteria requires gross and net reactive capability be determined within the power factor range at which the generating equipment is normally expected to operate. We do not believe anything is gained by testing in power factor ranges where the unit is not expected to operate.
No
First of all “expected value” is not defined. Second any expected value based solely on nameplate data is subject to great variation based on the system the generator is connected to and should not be used to draw conclusions of satisfactory or unsatisfactory test results.
Yes
Attachment 1 Item 1 requires testing of units that are 20 MVA and above to be tested a second time if they are tested as part of the aggregate.
Individual

Bob Casey
Georgia Transmission Corporation
Yes
No
This question seems to have identified the TO in error. MOD025-2 requires data to be submitted to the TP. TP is the appropriate entity to receive the data.
No
The ambient temperature and other factors that influence the ouput should be included. The GO should provide temperature dependent and other data tables/graphs to the TP. Again, the comment form and attachment seem to conflict with R1 and R2 to provide data to the TP not the TO.
Yes
No
Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability.
Yes
Yes
Yes
No
20 MVA seems more consistent with the reasoning in question 4.
Yes
No
The data should be accepted as is unless the data is meaningless.
No
No
Yes
Regarding reactive capability, the SDT has recognized that this standard will not meet the purpose “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability.” Should the standard and/or purpose be adjusted to where they match? Reactive capability cannot be determined, generally, without disturbances to the system. Long-term fault recorders could be installed at all generator high-side buses and verification of generation to any eventual disturbances could be used to get a better picture of the plants reactive power capability. R1.3 is unclear we propose: Submit the recorded data to its Transmission Planner within 90 calendar days of the date the data is recorded.
No
Yes
Yes
No

No
Yes
Have software manufacturers agreed to provide their models as described in R1?
Individual
Jeanie Doty
Austin Energy
Yes
No
We believe question #2 may contain a typo. The Proposed Standard Requirement 1.3 correctly requires data submittal to the Transmission PLANNER (in our case ERCOT). The data should be submitted to the Transmission Planner as currently written in the Proposed Standard, not the Transmission Owner as stated in the comment questionnaire.
No
Ambient temperature will have a less direct effect on water cooled generators with cooling water sources not directly affected by ambient temperature.
Yes
Yes
No
The ERCOT required verification time is 15 minutes. Extending the verification time to one hour is burdensome with unclear benefit.
Yes
Yes
No
This requires a guarantee to an expected performance that may be impacted by a particular operational problem during the test (high cooling water or ambient temperatures, etc). The test results should be accepted as is and logged as the new generator capability until such time as it is retested later with better results.
No
Yes
See the response to Question 6.
No

No
Yes
Yes
No
No
ERCOT has been performing computer modeling based on RARF data provided by GO's.
Yes
Since dynamic data for old units is often not available, the SDT may consider allowing the use of typical or generic modeling parameters for these units.
Yes
Yes
Yes
Yes
Yes
No
Initial compliance, within the first audit period, should be based on one evidentiary document set. Subsequent compliance, after the first audit period, may include the most current and the previous evidentiary document set.
No
No
Individual
Dale Fredrickson
Wisconsin Electric
No
The testing of reactive power capability has inherent risks due to the need for coordination with relaying and excitation limiters, and requires more technical resources than real power testing. Therefore the verification of real and reactive power would best be addressed in separate standards.
Yes
No
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
No
No
Yes
Attachment 1, 2.1 and 2.2: It would be more reasonable to allow for some small variation in real power level around the rated gross real power output and minimum real power outputs, perhaps within +/- 5 percent of these values. This would allow for variability in coal conditions, system voltages, etc. Also, the requirement in 2.1 for 90 percent of wind turbines online may be impractical in many cases. A lower value such as 75 percent may be more reasonable.
No
Yes
Yes
No
No
Yes
It is not clear how this standard would be applied to wind generators. They should perhaps be specifically exempted from these requirements.
Yes
Yes
No
The primary applicability should be to rotating synchronous machines which must have their protection settings and excitation controls properly coordinated with the machine capability. It is not clear how this can be applied to wind generators.
No
Replace the phrase "...preventing tripping..." with "...reducing the potential for tripping..."
Yes
No
The following should be added to the list in Section G: 1. under-excited limiters or minimum excitation limiters 2. over-excited limiters or maximum excitation limiters.
Yes

No
Yes
1. R1.2 needs to be clarified, and more time allowed. The phrase, "within 90 days following the identification or implementation of systems, equipment, or setting changes..." is vague, and should be replaced with "within 120 days of modifications made to systems, equipment, or setting changes...". The requirement should clarify that the clock starts 120 days after the date that the affected generator returned to service following the modifications. 2. It is not clear how wind generators can be subject to this standard. The information in Section G does not relate to wind machines.
Individual
Michael Brytowski
Great River Energy
Yes
Yes
No
GRE doesn’t agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load. If they want it at different points I think they should leave it up to the GO/GOP's to decide at what other load point they want to run the test.
Yes
GRE would object to doing this at URGE because URGE is not our normal operating condition. The reactive power testing should be done at normal full load (normal operating conditions) to be representative of how much reactive power the unit can put out or absorb during normal running conditions. GRE doesn’t agree with doing the under and over-excited limits at min. power levels. Mainly for baseload units, this is not representative of where the units run. Also, this would be costly when you are taking a baseload unit to min. load for the testing. There are also many unit specific conditions that exist that may prevent an unit from running at its true minimum load.
Yes
Yes
Yes
Yes
No
No
Yes
Please see comments submitted by the MRO NSRF for question #14

Individual
Vladimir Stanisic
BC Hydro
Yes
No
Not clear why would data be submitted to TO. Based on Functional Model, TP, TOP or PC would be more applicable.
No
Generating facilities are already designed and ratings determined based on maximum expected ambient temperatures. Besides, equipment cooling may not be directly dependent on ambient temperature. Providing the details to other entities would be of no practical value. GOs have to meet declared capabilities as registered or derate their facilities if needed.
No
In principle, using compliance registry as a sole criteria for applicability of Reliability Standards removes technical evaluation and justification from the process. The value that technical experts participating in SDTs may add becomes limited, which ultimately does not benefit the industry.
No
Technically, only verification at the maximu rated active power output has practical value since it is the most limiting operating condtion in terms of reactive power capability. Verifying reactive power capability at lower active power outputs is redundant because: 1. The capability will obviously be somewhat higher than at maximum active power output 2. Registration data normally include only Qmax and Qmin, which are determined at unit's rated active power output. 3. Reactive capability does not depend on unit's active power output as much as on other factors, such as system or station service voltages D curve is developed based on calculated data. The purpose of this should not be verification of the curve
Yes
It may be better to specify a particular rate of change of measured temperature determining that heating has stabilized instead of selecting an arbitrary time period.
Yes
Only verification of (1) has practical significance; (2) and (3) are redundant. Please see Comment 5.
Yes
Not clear why would verification be required for generating units over 20 MVA while for SCs the threshold is over 50 MVA, especially having in mind that SCs are specifically used to provide reactive support
Yes

No
Such a wide margin seems to defeat the purpose of verifications. If such margin is technically acceptable to planners, the question is why even requiring verifications, especially for smaller units. It is hard to immagine that actual capability (active or reactive) of generating units/facilities would ever be lower than 80% of declared.
No
No
No
No
Yes
This standard would not apply to SCs in any case
No
No
Yes
The standard apparently favours ambient monitoring as a verification method. While this method has certain advantages over methods traditionally used to verify response of turbine-governors (off-line and on-line step tests), it should be well understood that its implemention is associated with additional costs and difficulties. The question is how would GOs make use of ambient monitoring data to verify the models? GOs are responsible only for equipment models and would not normally have overall system models which are necessary to evaluate the results of ambient monitoring. That puts the focus back on traditional approaches.
Yes
No
Yes
Yes
Yes
Yes
No
Yes
The note in section G may have to be revisited. The main issue is that active excitation limiters can prevent a unit from unneccessary tripping during system transients. The standard should encourage activation and proper setting of avaiable excitation limiters
Individual
Michael Lombardi
Northeast Utilities

Yes
No
The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Yes
Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be "what you see is what you get"; adjustments should not be accepted.
No
Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by the BES SDT.
Yes
Yes
No
Regarding Part 2.1, in the NYISO reactive power is tested at a real power level above 90% of maximum. The tariff was designed in this manner for a few reasons: (1) not to be simultaneous test with 100% real power test and (2) provide a reliable maximum reactive test when the unit is stressed, but is still capable of providing reserve power. Recommend providing some flexibility in this requirement by stating that reactive power can be tested above 90% of maximum real power.
Yes
Yes
Yes
Yes
No
No
No
No

No
A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
No
Can’t generators be operated as synchronous condensers if needed?
No
No
Yes
In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
No
This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
No
Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Yes
Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage]. Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
No
Modify the wording to reflect all ‘real and reactive power sources,’ not limiting it exclusively to traditional rotating machinery.
Yes
Yes
No
The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
No
Yes
Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time

Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Group
Lakeland Electric
David Miller
Yes
Yes
A Transmission Owner may need to size conductors according to Generator output.
No
It should be acceptable that the Real Power data collected during credible, high-ambient temperature conditions be used to establish Real Power output limits throughout the year, including during lower temperature ambient conditions. By limiting Real Power output to that determined for high-ambient conditions, system reliability will not be compromised during lower ambient temperature conditions/scenarios.
Yes
In the VSL table for Requirement R2, the word “applicable” appears twice in a row in the “Lower VSL” and “Moderate VSL” columns. Propose striking one instance of the word.
Yes
No
The word “prior” lacks specificity. Proposed: “...shall retain the latest evidence of compliance with Requirement R1, Measure M1 dating back to most recent audit period.”

Group
PPL Generation
Annette Bannon
No
MOD-024 has already been incorporated into a regional standard by RFC (MOD-024-RFC); and, as is implicit in the term "standard," these documents should change only infrequently.
No
PPL Generation, LLC's Registered Entities are already performing VAR testing and reporting the results to our RTO (PJM), in accordance with Manual PJM-14D, and PJM then makes this information available to other entities. It would be very confusing to have to conduct two different VAR tests (PJM and NERC), possibly resulting in two different values (depending on the final wording of MOD-025), reported to two different entities.
No
The correction of real power capability to other-than-tested ambient conditions, as is currently performed by PPL Generation Registered Entities for MOD-024-RFC, is a complex matter involving the wet-bulb temperature, condenser cleanliness and other factors beyond simply the dry-bulb temperature, especially when using a total-unit thermodynamic computer model for this purpose. One must also consider low-ambient limitations; wintertime predicted capabilities must be truncated if they would otherwise exceed the generator or GSU rating. Corrections to other-than-tested ambients should be performed by the GO, using an on-request basis.
No
The applicability of this standard should include, "and having a capacity factor for the past three years averaging over 10%." As presently written this standard would require VAR testing of a small, emergency genset if located in a baseload facility interconnected > 100 kV.
Yes
The proposed verification at multiple points over a unit's operating range appears to derive from a belief that the verification test results will follow the generator OEM's D-curve; and, owing to the abnormal voltages created by VAR testing and aux bus drop-out limitations; this will not be the case.
No
The one-hour period appears to derive from D-curve (thermal limiting) expectations; and, as explained above, this will not be the case
Yes
Yes
Yes
Yes
Yes
Note however that the expectation, as discussed above, is (for certain PPL Generation Registered Entities' units) derived form the aux bus limits, not the D-curve.
No
Yes
Ref. the inputs made above, there should be just one VAR test, with a single set of results going to all parties.
Yes
PPL offers the following comments on Attachment 1: Att. 1. para. 2: Change the final sentence to

end, "within 20% of the expected real and reactive power values." Reason: Clarification Att.1, footnote to para. 2.1: Change "normal expected maximum" to "normal," and "at the time of the verification" to "for the ambient conditions during the verification." Reason: Clarification. The normal output of a unit is often not its (emergency) maximum generation, and the word "ambient" works better than "time." Att. 1, para. 2.1, 1st sentence: Change "at rated gross Real Power capability" to "within 20% of the Real Power capability." Reason: Clarification, see the comment above to para. 2. Also, the terms capability and rating have different meanings. Att. 1, para. 2.1, last sentence: Change "possible" to "practical" Att. 1, para. 2.2: Change exception in 1st sentence to "other than wind, photovoltaic and peaking (capacity factor < 10%)." Reason: Given that peaking units typically operate only during periods of maximum demand, it can be difficult to establish a realistic min power expectation, this exercise would add little or no value, and such testing would be unnecessarily economically burdensome. Att.1, para. 2.3: Add at end, "for baseload units. Values for peaking units (<10% capacity factor) may be recorded as soon as they are reached. Reason: The dispatch volatility of peaking units can make a one-hour hold-period unnecessarily economically burdensome. Att. 1, para. 2.5: Add at end, "if attainable. Otherwise a 10% variation is acceptable" Reason: Hydrogen pressure can vary, and minor disturbances should not disquality an otherwise-acceptable test. Att. 1, para. 3.2: Clarification is needed. Is the standard saying that a special-for-test voltage schedule should be established with the RTO? Att. 1, para. 3.3: Add at the end, "one or the other of these values may be calculated, if metering is not present at both locations." Reason: Same concept as para. 4.1. Att. 1, Note 1, 1st sentence: Add at the end, "or unit auxiliary system voltage limits or facility operational practices." Make the same change also for "transmission system conditions" in the third sentence. Reason: VAR testing involves creating abnormal voltages at the generator terminals and in the feeds to auxiliary equipment. Drop-out of aux motors can constitute the practical test limit. It is appropriate to apply safety margins in this respect (ref. facility operational practices), lest units be at risk of tripping in the course of conducting a reliability test. Att. 1, Note 2: Clarification is needed regarding the less-restrictive conditions being referred-to. Att. 1, para 3.4: Replace "and a correction factor...if needed" with "and, if requested, correction to other ambient conditions." Reason: Correction often involves more than a simple multiplication factor, especially when using a thermodynamic computer model for this purpose. This exercise includes truncating corrections to lower ambients for GSU and generator limits, if necessary. General: The generator OEM D-curve constitutes a rating, not a capability, and is applicable only at rated voltage. VAR testing involves identifying a capability at abnormal voltages, and is thus likely to rarely if ever match the D-curve. General: Where the RTO has an effective VAR testing program in place (as is the case for PJM) the results should be acceptable as-is for NERC compliance purposes, lest there be created two different tests, resulting in reporting of two different reactive capabilities to two different entities.
No
Yes
Yes
No
No
Yes
PPL Generation suggests the following changes: 1. Increase the capacity factor threshold identified in the Applicability Section from the current 5% to 10%. Otherwise, ambient monitoring may be required for an excessively long period. 2. Allow the use of OEM-provided governor models and, if adequate, existing models to satisfy the requirement in R2. OEM models can have equivalent-or-better validity than on-line testing. 3. Define what response is expected to be documented for Requirement 2.1.1 (as pertaining to a time-frame of 30 seconds or less, and to sudden frequency dips, not step-increases). Units have an immediate response (e.g. opening the control valves) and a long-term response (e.g. ramping-up the coal feed). Governors (the subject of this standard) deal only with the former category. Ambient monitoring should eventually provide a frequency-dip event to analyze, but the same is not true for opposite-direction events. 4. Should the recorded response in

Requirement 2.1.1 be the predicted response? It appears that the on-line response and the recorded response are the same thing. 5. In Requirement 2.1.1, clarify under what circumstances a lack of response constitutes suitable verification, e.g. experiencing a frequency drop for units running valves-wide-open or CTGs at baseload firing temperature.
Yes
No
See item 1 in Question 9 Response.
No
No
As stated in comment 2 for item 9 below, NERC is not being consistent in using the term "capability." It refers in other standards to that which can be achieved, not to the condition at which tripping is needed.
Yes
No
Yes
No
See comment 2 for item 9 below.
Yes
PPL Generation suggests the following changes: 1. Consider making this standard applicable to generation facilities having a capacity factor for the past three years averaging over 10%. The basis for this request: As presently written this Applicability would require compliance for a small, emergency genset if located in a baseload facility interconnected > 100 kV. 2. In Requirements R.1, R1.1.1, R1.2 and elsewhere where the term "capability" is used, consider using the term "trip limit". As currently written, it appears that Requirement 1.1.1 is semantically misdirected in requiring protectives to be set below equipment capabilities. A capability is what the unit can actually do (ref. MOD-024 and 025). It is not the limit beyond which damage, instability or other problems may occur. A unit with a 875 MVA GSU and 900 MVA generator, for example, may have a real power capability of only 750 MW based on boiler and turbine limitations. It is not possible to have trips set below a unit's capability, unless PRC and MOD apply different meanings for this term, which would not be suitable. Confusion may be caused by generator D-curves also being called “capability curves,” but here also one would not want to require that generator never be operated at the D-curve value.
Individual
Amir Hammad
Constellation Power Generation
Yes
Yes
No
Constellation Power Generation (CPG) agrees with this approach.
No
Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
Yes

CPG agrees that the points chosen would provide a sufficient approximation of a unit's capabilities. However, these capabilities will never match a generator's capability curve for a multitude of reasons, and as such, some verbiage should be included in the attachment under item 2 instead of as a note at the end of the document. Further, the limitations on the unit that may not allow the unit to perform to its capability curve are most likely designed into the control system as limiters or protection system components so as to not allow damage to the unit. These designed controls should not be "investigated for resolution" as stated in Note 1.
Yes
Yes
Yes
Yes
Yes
Yes
No
No
Yes
CPG is concerned with the general wording of Attachment 1 as the verbiage is not auditable. For example, Item 2.1 states "Maintain as steady as possible Real and Reactive Power output during verification." The term "steady as possible" is extremely subjective and open to a multitude of interpretations. From a technical perspective, item 3.3 is not auditable because it is assuming that the voltages and the high and low side of the GSU are metered. This is usually not the case. A statement allowing for an entity to report on the requested metered points based on their configuration and allowing for some points to not be answered would be preferable. Likewise, Attachment 2 would require a similar statement.
No
No. CPG believes that the use of capacity factor, a variable data point, in the applicability of a standard is too problematic. Capacity factor is a market a function that is dependent on many variables outside of reliability and therefore does not belong in a reliability standard. CPG is also unsure as to how the SDT arrived at the MVA thresholds in each of the Interconnections, and is requesting that a technical justification of those thresholds be submitted along with the response of comments.
Yes
Yes
No
No
Yes
CPG is unsure as to what Requirement 2.1.1 is actually requiring. Please explain the difference between an on-line response to a frequency excursion vs. a recorded response. This sub requirement seems to be implying that each GO has the necessary equipment to capture an on line or recorded response. Is it the intent of the drafting team to force GOs to install equipment in order to comply

with R2.1.1 along with the conditions found in Attachment 1? CPG would also like clarification on Requirement 2.1.5. Outer loop controls don't affect the governor control (frequency loop). Lastly, CPG would like the SDT to describe how a GO will know that a frequency excursion event occurred on the BES if their facility was unaffected and the facility did not have equipment sensitive enough to measure within .15 Hz.
No
Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
No
Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
No
No
Although CPG believes that the purpose of this standard is valid and accurate, it closely resembles the purpose of PRC-001 and therefore the requirements drafted in PRC-19 should be rolled into a revision of PRC-1.
Yes
No
CPG believes that engineering documents detailing the coordination of the these components should be sufficient in lieu of coordination plots requiring software that is not commonly used by generators.
Yes
No
No
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes
No
The Transmission Operator (TOP) and Transmission Planner (TP) are far more likely to need and use the data and models identified and dispatch the units in their market area. In New York, the NYISO as the TOP is responsible for real-time modeling and dispatch (specifying both real and reactive schedules), and as TP the longer term modeling. The Transmission Owners (TO's) do not have this type of relationship with the Generation Owners (GO's) and Generation Operators (GOP's). R1: A standard should be developed that makes reactive power testing mandatory for all units above 75 MVA. This standard will provide the TOP with critical information on the total dynamic reactive capability of dispatched generation.
Yes
Real and reactive power output is affected by the thermal conditions in effect a t the time of testing and dispatch. The output of a generator, and therefore the model of its output, can be more or less temperature dependent, e.g., a combustion turbine with versus the same combustion turbine without

inlet chillers. Attachment 1 specifies that the temperature only be recorded at the end of the verification period. Temperatures can vary significantly over the course of the verification period, and at a minimum the ambient temperatures at the beginning and end of a verification period should be recorded. It would also be meaningful and helpful to record ambient temperatures at intermediate points during a verification period. The Real Power data submitted should not be adjusted to a temperature other than ambient. When collecting real time data, it should be “what you see is what you get”; adjustments should not be accepted.
No
Generally, only units larger 75 MVA are impactful. It is recommended making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with current draft BES definition being prepared by BES SDT.
Yes
Yes
No
We recommend allowing the Transmission Operator (TOP) flexibility in determine the specific detailed nature of the reactive power tests performed in support its modeling. Regarding Part 2.1, in the NYISO, the maximum reactive power is tested at a real power level above 90% of maximum real power capability. The test was designed in this manner for a two reasons: (1) not to be a simultaneous test with 100% real power test and (2) to provide a reliable maximum reactive power test when the unit is stressed, but is still capable of providing reserve power. We recommend providing the TOP flexibility in this requirement by allowing reactive power to be tested above 90% of maximum real power capability. The NYISO Ancillary Services Manual also contemplates that GO’s will test lagging and leading reactive power during time periods more appropriate to their use. On p. 28 and p. 34 the manual states: • Lagging MVAr capability testing will normally be performed during on-peak hours. The VSS Supplier must operate at maximum Lagging MVAr for at least one hour for the test to be acceptable. • The Leading MVAr testing will normally be performed during off-peak hours. The Leading MVAr test shall be scheduled with the corresponding TO, who will inform the NYISO. Ref: http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf Presumably, under the NYISO tariff the leading and lagging Reactive Power tests would not be performed at the same time or necessarily at the same “rated gross Real Power capability.” ISO-NE also notes that maximum leading and lagging reactive power may not be at the same real power output level. • Points #4 and #9 in Figure #1, the two [lagging and leading] break points, do not necessarily correspond to the same MW output of the Generator. Ref: http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14b_rto_final.pdf Proposed language change to MOD-025 Attachment 1: 2.1. Perform verification of Real and Reactive Power capability of all generating units at maximum over-excited (lagging) and under-excited (leading) reactive capability at rated gross Real Power capability1, or at the Real Power level stipulated by the Transmission Operator. ...
Yes
Yes
Yes
Yes
No
No
No

No
No
A Planning Coordinator should be able to request a review of turbine/governor and load control or active power/frequency control system model even though response is not consistent from one frequency excursion event to the next from any unit connected to the power system. If not being listed in the Applicability section is an issue, then the wording should be changed in the Applicability section so as not to preclude the Planning Coordinator from collecting necessary data.
No
Can't generators be operated as synchronous condensers if needed?
No
No
Yes
In the Applicability Section, why the differences between the Eastern Interconnection/Quebec and WECC in generating unit and plant sizes specified?
No
This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
No
Generally only units larger than 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by the BES SDT.
Yes
Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage]. Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
No
Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Yes
Yes
No
The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
No

Yes
Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Individual
Thad Ness
American Electric Power
Yes
In general, AEP is not opposed to combining MOD-024-1 and MOD-025-1 into a single MOD-025-2 standard.
Yes
Draft Standard MOD-025-2 provisions 1.3 and 2.3 both state that the data be provided to the Transmission Planner, rather than the Transmission Owner as stated within this question #2. We agree that the Transmission Planner is the correct recipient for this data.
Yes
Again, we believe the question should be associated with the providing of ambient temperature and correction factor information to the Transmission Planner and the Resource Planner rather than the Transmission Owner. We believe the Resource Planner should provide the ambient temperature value, while the Generator Owner should provide the correction.
Yes
Yes
The results of the test may not accurately reflect the VAR capability due to system conditions or alarm stopping the test and not reflect the actual generator limit in a real time scenario. This is discussed in Notes 1 and 2 of Attachment 1.
Yes
This requirement is stated in Attachment 1, section 2.3.
Yes
This is stated in Attachment 1, section 2.4. A clarification could be in order to relate the recording of the time when the limit is reached to the requirement that the test be conducted over a one hour interval. For example, if a limit is reached in 15 minutes, is the verification test completed or is the expectation that the unit is held at that level for the balance of the one hour test window. Also, it is curious why this question excludes the condition of over-excited reactive capability at the rated gross real power per Attachment 1, section 2.1.
Yes
Yes
The current draft of the standard in section 4.2.1 proposes that the size of synchronous condensers to be verified be limited to those greater than 20 MVA, not 50MVA as stated in this question. Regardless, either limit would be acceptable.
Yes
No
System conditions greatly affect the expected reactive power values as stated in Attachment 1, Notes 1 and 2. While 20% appears reasonable for the real power verification, there needs to be flexibility as to this value for reactive power, given that system conditions are not constant.

No
With respect to reactive power, AEP is not aware of any regional variances that would be required for this standard.
No
AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
No
No
Yes
Yes
Synchronous condensers respond to changes in voltage and not frequency, and as a result, have no place within the scope of this standard.
No
AEP is not aware of the need for any regional variances that might be required as a result of MOD-027-1.
No
AEP is not aware of any conflicts between the proposed MOD-027-1 and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement.
Yes
Standard models may not be available for wind units and wind facilities (which appear to be within scope of 4.2), particularly aggregate reactive and frequency response controls. As a result, it might be difficult to obtain and provide such information.
Yes
Though we agree that the standard as written is “technology neutral”, its apparent neutrality might well be impacted by the definition of BES which is currently being revised. This topic might need to be revisited once the revised definition of BES has been approved.
No
It needs to be explicitly stated whether or not a Transmission Owner is held under R1 if they do not own synchronous condensers. This might be achieved by adding additional language to 4.1.2 stating that the standard applies to those who own facilities as specified in 4.2. Usage of the words “coordinate” and “coordination” seems ambiguous, and might be open to interpretation. In other standards these words are often used to describe communication between NERC functions rather than ensuring that necessary and sufficient settings exist among equipment types to permit them to operate in a pre-determined sequence. The threshold of 50MVA is not mentioned in the draft standard. Rather, 4.2.1 specifies a threshold of 20MVA. It appears the term “synchronous condenser” has been omitted from R1. Suggest using "Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate its generating unit, generating Facility, or synchronous condenser voltage regulating system controls, including limiters and protection functions with the generating unit and Facility or synchronous condenser capabilities and protective system settings; to include as applicable".
No
AEP sees no benefit to the reliability of the BES in adding to this standard the controls associated with static reactive resources.
No
We are concerned by the inclusion of “protection system settings” in how it might differ from, or be confused with, the NERC defined term Protection System. The term “generator capabilities” should be removed from the purpose statement (as well as the requirements), as it is general enough of a term to make proving compliance difficult.
No

In light of the many other changes to standards currently proposed, and their implementations, AEP would suggest an additional year to the proposed implementation schedule to ensure a successful adaptation to PRC-019-1. The effective date for the 20% compliance milestone is inconsistent between the draft standard and the implementation plan, with one document allowing one year for compliance and the other allowing two years.
No
There appear to be inconsistencies between the standard and appendix G. the standard uses the term “protective system settings” and “protection system settings” while the appendix uses the term “protection function”.
Yes
No
AEP is not currently aware of any need for regional variances to this standard.
Yes
Measure 1 states the need for “one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2.”, yet this would not be required by the standard until five years following the initial coordination.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP agrees that generator reactive testing necessarily requires validation at the real power extremes. This means there is no benefit to require separate testing.
No
Cogeneration LP believes that the proper recipient is the Transmission Planner. The Transmission Planner in turn must supply the information to the Planning Authority, Reliability Coordinator, and/or Transmission Operator as needed. There is no apparent reason why the Transmission Owner should be in the loop. Attachment 1, Item 3.4 seems to be the only place in MOD-025-2 that the Transmission Owner is shown as the recipient of generator verification data. It should be changed to Transmission Planner – consistent with the rest of the standard.
Yes
As with question #2, we believe the appropriate recipient of generator verification data is the Transmission Planner, not the Transmission Owner. Secondly, the Generator Owner providing the validation data must also be responsible for any corrections based on ambient temperature – as there may complexities beyond temperature correction factors. In these cases, if the TP performs the calculation, they may otherwise assume more capacity is available in their contingency assessments. The GO should have the option to provide the actual validation results to the TP with a temperature correction factor, but ultimately that decision rests with them. Third, the Transmission Planner must provide the required operating temperature range necessary for their system models. This will assure consistency among generators operating within their planning jurisdiction. If there are any discrepancies between the GO’s and TP’s expected range of operation, they can work that out through an iterative resolution process – similar to the structure suggested in MOD-026-1 and MOD-027-1.
Yes
These applicability criteria are consistent within the Regions that Ingleside Cogeneration has familiarity with (TRE, WECC, and SERC).
Yes
These operating points are more than sufficient to validate reactive capability in accordance with FERC’s directive. However, Ingleside Cogeneration LP believes that it is sufficient and far less risky to perform the validation at the TOP’s reactive capability schedule limits. In addition, there needs to be an allowance for known equipment limitations which prevent testing at the four test points. Similarly, unforeseen limitations which are determined during testing may prevent the validation at every extreme.
No

Ingleside agrees in principle that one hour is sufficient at this test point, but believes it should take place at the limit identified in the Transmission Operator’s reactive capability schedule.
No
Ingleside agrees in principle that a demonstration that the generator can reach these test points is sufficient, and reduces the risk to the equipment. However, the limits identified in the Transmission Operator’s reactive capability schedule should be verified, not the generator’s operational limits.
No
There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.
No
There is a significant body of work underway defining the extent of the Bulk Electric System, which this proposal bypasses. This determination should rest with the project team responsible for that effort.
Yes
There is no reason to preclude the use of actual operations data in validation exercises.
No
The real and reactive capacities should be validated to be within 20% of expectation at the limits identified in the Transmission Operator’s reactive capability schedule, not the generator’s operational limits.
Yes
TRE, WECC, and SERC have similar but slightly different requirements. It is Ingleside’s expectation that these regions would align their processes to MOD-025-2 when it takes effect.
No
No
No
Yes
MOD-027-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES frequency response – and have already the recording equipment needed to validate performance.
Yes
There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Yes
In the TRE region, there is already a generator governor/frequency response standard under development. It is not obvious to us that the TRE standard aligns with MOD-027-1.
No
Yes
Like many Generator Owners, Ingleside Cogeneration LP has limited experience with transmission system modeling and scenario planning. Although in general we have a good working relationship with our Transmission Planner, MOD-027-1 may border on exchanging information which either entity may consider to be proprietary. In addition, the extra costs required to deploy recording equipment and to engage external experts to assist with frequency response planning are not budgeted. With

this in mind, a priority deployment may be more appropriate – where the most critical facilities in each Region are evaluated first.
Yes
Ingleside Cogeneration LP's gas and steam turbine units use voltage limiting and protection system technologies which are clearly referenced under PRC-019-1.
No
PRC-019-1 is appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System – this determination should rest with them.
No
Ingleside Cogeneration LP is hesitant to require validation of components which have not been clearly identified as a reliability imperative under either the revised definition of the BES or CIP-002-4's bright-line criteria.
Yes
Yes
The five year phased-in validation of settings is sufficient for Ingleside Cogeneration LP.
No
Ingleside Cogeneration LP agrees with the concept of establishing a mode of operation that allows voltage regulators and limiters the first opportunity to deal with a voltage transient well before the corresponding Protection Systems are activated. However, we are concerned that protective relay settings must be always set in accordance with the Steady State Stability Limit (SSSL) as defined by NERC. There may be factors that are more limiting which require more sensitive settings – which should be acceptable if demonstrated on a P-Q, R-X or similar graph.
Yes
No
No
Group
Dominion
Louis Slade
Yes
No
R1.3 and R2.3 require submittal to Transmission Planner, not Transmission Owner. We believe it is also appropriate to submit these results to the Resource Planner as we are unaware of an existing reliability standard that requires this information be provided to that entity (even though aware that version 5 of the Functional Model (on page 28) states the Resource Planner "Coordinates with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans." Further, we believe it is also appropriate to submit these results to the Balancing Authority and Transmission Operator despite the fact that they may request verification pursuant to TOP-002a @R13. We believe that, given the owner is being required to verify real and reactive capability, and report the results to one entity, requiring reporting to additional entities who could find the information useful in its reliability assessment (whether in the planning or operating time horizon) adds significant value at little additional effort.
Yes
We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that compliance with this standard be based solely upon the requirements contained

within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Yes
No
We believe that, if the Resource Planner or Transmission Planner desire use of any correction factor, other than ambient, they be allowed to request the GO or TO adjust for that (those) correction factor(s) but that compliance with this standard be based solely upon the requirements contained within. If a RE desires to impose additional correction factor(s), it should file for a regional variance to this standard.
Yes
No
For items 2 and 3 see comments in question 5. We agree with item 1.
Yes
No
First, we would like to state that we did not see the 50 MVA threshold in the posted version of this standard. And, if we had, we would not have agreed. If 20 MVA is the appropriate threshold for a generator, it is appropriate for a synchronous condenser.
Yes
No
If the question was meant to ask whether we agree with the sentence that reads" Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" (Attachment 1, @2) tehn we respond affirmatively. However, we do not agree that a verification MUST be within 20%. It is possible that a physical change to either the asset being verified or the system it is interconnected with may result in its inability to perform to within 20%. If this is true, then we could agree that any such variance must be accompanied by an explanation as to why the verification did not fall with the 20% 'boundary' There should be no requirement for percent of expected value.
No
No
Yes
Test form needs to be improved. Provide the form in format that can be electronically completed by the user.
No
Yes
Yes
No
No
Yes
While we understand that a significant portion of the industry supports the 5% capacity factor threshold, we believe that this term is subject to different uses by various entities and parties,

particularly biased as to whether one is discussing capacity or energy. We suggest that, for the purpose of this standard, capacity factor be described as defined by NERC GADS. Please elaborate on Requirement 2.1.5. Also, we believe that “Load Control” and “AGC” are the same. R3, the third bullet, we suggest that “did not match the recorded response for three or more transmission system events be changed to “did not approximate the recorded response for three or more transmission system events “ We believe there needs to be an exception allowed if a frequency event does not occur in 10 years. What is “staged test” mentioned on Attachment 1? Also Attachment 1 is very confusing and should be rewritten.
Yes
Yes
No
Yes
No
The effective date implementation schedules contained in the standard and the associated Implementation Plan do not agree. Specifically, the standard indicates one year following regulatory and/or Board of Trustee approval where as the Implementation Plan indicates two year. Additionally, the standard at Step 5.2 does not include a sub-step for 100% of applicable units.
Yes
Yes
No
Yes
1) the phrase “Generating equipment”, in the 3rd bullet of R1, be changed to “Generator” to be consistent with the usage under bullets 1 & 2. 2) The title and purpose of the document do not address synchronous condensers as addressed in Requirement R1; 3) if the standard includes synchronous condensers, why are static VAR compensators not included? The following bullets under R1 are too generic. Should specifically outline required parameters. In-service 1excitation system and voltage regulating system control, limiters and protection functions • In-service generator or synchronous condenser protection system settings • Generating equipment or synchronous condenser capabilities • Steady state stability limit We recommend replacing the bullets with the following: • Generator or syn. Condenser capability curves. • Steady state stability limit. • Loss of field zone 1. • Loss of field zone 2. • Loss of field trip. • Under excitation limiter. • Over excitation limiter. • Power factor line. • Backup over current settings. • Instantaneous field current trip. • Instantaneous field current limit. • Volts per hertz.
Group
Salt River Project
Cynthia Oder
Yes
Yes
No
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
No
No
No
Yes
Yes
Yes
No
No
No
Yes
Yes
No
Yes
Yes
Yes
Yes
No
No

Individual
Hamish Wong
Wisconsin Public Service Corp
Yes
Yes
Yes
Yes
Yes
No Comment.
Yes
Yes
No
Synchronous condensers are specifically for local area voltage regulation purposes. Units between the sizes of 20MVA to 50MVA could be significant to an area's dynamic performance under contingencies.
Yes
No comment.
No
No
No
No
Yes
We agree with this proposal as being in line with our overall concern that model verification requirements should be based on cost efficiency and practicality. Facilities outside of the Applicability Section are already judged to be of minimal significance in dynamic impact, and are also typically of vintages and origins whose modeling data and parameters are difficult or impossible to obtain. For facilities of minor dynamic impact in a locality, typical or surrogate model data would serve the simulation purposes the vast majority of times.
Yes
It is our opinion that synchronous condensers, when in operation, are intended to regulate local voltages but not for regional frequency control.
No
No
Yes
We have a number of questions and concerns as follows: • While the Standard uses the word “verified” and “verification” loosely, it is not precisely clear what a GO would have to do to satisfy the

verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • The response of a unit is dependent on the instantaneous conditions of the external system to which it is connected at the time of the disturbance, in addition to the inherent response characteristics as built. This may result in the modeling parameters derived based on on-line frequency/Load excursion test not being unique. • If a simulation study results in response characteristics that does not match an on-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? • We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for turbine/governor was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, excitation controls, SVCs, HVDC Converters, boiler/burner controls, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Group
FirstEnergy
Sam Ciccone
Yes
We agree that a “one-stop-shop” approach is appropriate for Real and Reactive Generator Verification requirements.
No
The standard in Subpart 1.3 says that the Transmission Planner is the entity that shall receive this information. We agree that it should be the TP. Also, we question whether or not the Planning Coordinator should also receive this information. Furthermore, with respect to how this information will be used by the planning entities, the team needs to assure that there is no duplication of efforts with MOD-010-0 and MOD-011-0. We suggest that MOD-010-0 and MOD-011-0 get revised to remove redundancies, or make it clear the the entity may supply existing MOD-010/-011 compliance evidence to show compliance with MOD-025-2.
No
We believe that it is the responsibility of the Generator Owner to have an appropriate Ambient Adjustment Methodology and make the necessary corrections to the data per its methodology before submitting it to the Transmission Owner. We suggest similar requirement regarding ambient ajustments as found in regional standards MOD-024-RFC-01 and MOD-025-RFC-01.
Yes
We agree that this standard should be consistent with the NERC Compliance Registry.
No
As a TO, we rank the importance to the modeling effort as follows: (1) Pmax, Qmax; (2) Pmin, Qmin; (3)) Pmax, Qmin. We believe that the Pmin, Qmax is of little value to a Planning Engineer.
Yes
Although we are OK with the 1 hour interval, we are not convinced this will meet the reliability goals

of the standard. Just being able to hit a specific reactive output is one thing, but that does not assure Reliability. Most large generators and large main transformers have only reached one, possibly two, thermal time constants within an hour timeframe There are many thermal problems that can be identified if the electrical equipment is permitted to be operated at high load levels over an extended period of time. It may be necessary to show that reactive output can be maintained over a longer period of time.
Yes
Yes
Yes, we believe they should be verified because they are the same type of dynamic, voltage independent, source of reactive power as is a real power generator. We also believe that they certainly are generators, generators of reactive power. In fact, they are identical in function, design and equipment as a real power generator, minus the prime mover. A synchronous condenser, like its sister the real power generator, can be continuously adjusted for the desired output and contains equipment that must be properly adjusted to provide the desired range of reactive output.
Yes
The applicability section does not mention the 50 MVA threshold.
Yes
No
If the generating unit is capable of reaching 20% of the "expected value", than why should verification be concluded at that point? (We could potentially be missing out on fully realizing the potential of a reactive resource by pre-maturely ending the verification. A very important dimension of this verification (that was touched on in the Standard) is the recognition of equipment conditions or voltage regulator settings that could be improved when a staged test is performed. It is difficult if not impossible to capture equipment shortcomings or limitations which can be very useful to improving operations when verifying through the use of Operational data. Also, we need clarification regarding what would be considered “within 20% of expected value” if your leading reactive limit was 0 MVAR (unity)?
No
Yes
Regional Entities such as RFC currently have Real and Reactive standards in place for its members and will need to evaluate the need to keep their standard or revise it to remove any inconsistencies that may exist. One inconsistency is the periodicity of verification for real power.
Yes
Regarding Notes 1 & 2 in the standard: Generally we have found that reactive power limitations that originate inside the generating station (hydrogen pressure, thermally sensitive generator, voltage regulator settings, and excitation problems) usually cannot be overcome through engineering analysis on the part of the transmission planning engineer. These types of conditions can only be addressed by the GO. On the other hand, Generator Terminal Voltage limits, or Transmission System voltage Limits can be eliminated using engineering analysis to simulate a more stressed system. Attachment 1, R2 – Assuming there are no transmission system related limitations, how close does the test value for VARs have to come from the expected value to be considered “verified”? Attachment 1, R2.2 – Nuclear units should be exempt from having to test leading VAR capability as this would challenge the plant’s licensing limits for safety bus minimum voltage. MOD-025-RFC-01 currently allows this exemption for nuclear plants. Attachment 1, NOTE 1 – For clarity, nuclear plant safety bus voltage limits should mentioned as a reason why D-Curve values may not be met during a test.
No
Yes
Yes

No
No
Yes
As a result of the 2010 NERC Generator Governor Survey, it became clear that many nuclear units (and I believe all of the BWR units) do not respond to changes grid frequency because their governors are controlling steam pressure. The standard should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that “Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units…”. For those nuclear units that are able to respond to overfrequency events there is a possibility that a response to a system transient may not be seen during a ten year period. Since responding to an overfrequency event will result in a drop in unit load and a corresponding change in reactivity, the governor control dead band, which is set to minimize the possibility of a spurious reactivity change, could be large enough to ignore an event that meets the frequency excursion threshold (for example a 0.1 Hz dead band would ride through on a 0.07 Hz excursion). Likewise a nuclear unit would not perform a frequency reference change input test with the unit on-line because of the resulting change in reactivity. Would injecting a frequency signal to the EHC during off-line calibration and noting the response be acceptable?
Yes
Yes
Although we agree with the applicability, the standard that was posted does not mention the 50 MVA threshold.
No
Yes
Yes
At the moment we do not have comments on the proposed measures. We will review the proposed measures on the next draft and provide out input.
No
Section 1.2 of the Compliance section is missing a time frame for data retention. Timeframes consistent with CEA routine audit cycles should be added to this section.
No
We are not aware of the need for a variance at this time.
Yes
M1 requires that the GO will have evidence that “…voltage regulating system controls and protection functions are coordinated with the generating unit and generating Facility capabilities and protective system settings applied to in-service equipment as specified in Requirement R1, Section 1.1, and one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2.” For the first verification cycle this would require that units would have to prove compliance as much as 4 years before the standard became enforceable. This is akin to setting up a traffic camera in a 35 mph zone in March, changing the speed limit in that zone to 25 mph in July, and going back and writing tickets for every car that exceeded 25 mph from March through June. This needs to be clarified. Requirement R2 (shown as 1.2 in the standard) should have a violation risk factor of MEDIUM instead of HIGH. Furthermore, it seems that the phrase “within 90 days of making a change to the generating equipment, voltage control limiter

settings, or protective function settings that would affect the coordination" is not necessary because a change to equipment setting would already require coordination per Requirement R1. We suggest removing this part of 1.2 (or R2).
Individual
Gary Chmiel
GE Energy
Yes
No
No
Yes
The second bullet, in part B "Requirements," section R1, page 4: The word "library" should be removed from the phrase "system model library block diagrams," since not all wind manufacturers have standard library models.
The fourth bullet in Part G "Reference," paragraph beginning with "Equipment limits,", page 6: The word "stator" should be removed, in order to make the over voltage protection limits applicable to non-synchronous machines.
Individual
Kathleen Goodman
ISO New England
Yes
No

The data from MOD-25-2 should be submitted to the Transmission Operator. The Transmission Owner does not appear to be the correct functional entity. The Transmission Owner may not have the area view required for this testing. Real and Reactive Power Testing must be coordinated with the Transmission Operator to ensure that the system remains within all operating limits.
No
We maintain that temperature correction should be performed as required by the Transmission Operator. The standard must ensure that accurate data for gas turbine and combined cycle generators is obtained which can be adjusted to reflect the ambient temperature presumed in Planning Assessments.
Yes
Yes, however the standard should not rewrite the Compliance Registry as attempted in section 4.2. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry's wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity's restoration plan. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
No
Performing testing for lagging capability at minimum real power output especially would require an inordinate amount of planning to ensure that transmission voltage levels in the local area are not exceeded. Testing requirements should be changed to two points, one for an hour to verify over-excited reactive capability at rated Real Power and one at minimum Real Power output to verify under-excited capability. Also the test of leading capability at minimum real power loading should be held for five minutes. These tests are adequate to verify critical characteristics of the generator for use in studies. The four point tests may be difficult to obtain given system configuration and operation.
Yes
Yes, the standard should also require a recording of generator vibration during the test and require that the Generator Owner report an increase in vibration over the test period indicating the presence of rotor shorted turns that would limit long term generator MVAR loading. One hour may be enough time to determine if rotor shorted turns are present as indicated by vibration but the vibration must be recorded. The reactive power output data recording should be at 5 minute intervals and use the average for the hour. Also testing leading capability at minimum real power loading should be held for five minutes.
No
These types of tests should require remaining at the point for a length of time. Under-excited power verification at minimum power output for five minutes should be adequate. Testing requirements for over-excited reactive capability at minimum real power output and under-excited capability at maximum power should be removed. These tests lead to transmission system voltage concerns.
Yes
Yes, but as written the standard is not clear as to how the testing is to be performed for a synchronous condenser.
No
There is no technical justification supporting the 50 MVA criterion. Absent this, we propose to use the Compliance Registry criteria for generators of 20 MVA as a general criterion for data being verified for synchronous condensers over 20 MVA as well.
Yes
No
As we interpret the language, we do not agree with the 20% requirement. In the assessments performed in our area our goal is to use data that is much more accurate than what appears to be required under the standard. Allowing verification to be up to 20% inaccurate may result in inaccurate system assessments, potentially leading to overlooking potential system problems or to unnecessary system investment to address system concerns which are not really present. This value should be changed to a maximum of 5%.

No
No
The obligations set by this Standard are less stringent for Generator Owners/Operators than those contained in ISO-NE’s Tariff. In addition, FERC’s Standard Generation Interconnection Rules make clear that material changes to generation facilities (which would include changes to reactive power capabilities) must be reported to the Transmission Service Provider prior to the change being made. The Standard Drafting Team should consider whether language is appropriate to make clear that the Standard is not meant to displace obligations to report reactive power capabilities already contained in Transmission Service Providers’ tariffs.
Yes
• Effective Dates: This proposal is not well explained and very well may not work. Some concerns that arise: (a) For those GOs that have units in multiple control areas, are they supposed to apply the Implementation Plan for their entire fleet or for their fleet on a per Region basis? This same issue can apply to TOs which may be in multiple areas. This seems impossible to track and may leave some areas without any verification for 5 years after the standard has been approved. The Transmission Operator should be given the discretion to require and approve a test schedule within it’s area. (b) For those GOs with only one or two facilities in a region, how will the 5-year implementation plan work? Will the GO with one facility in a region have 5 years to implement (i.e., the 100% rule would not “kick” in until 5 years out, or will the GO with one facility in a region have only 1 year to implement (since 20% of 1 unit would arguably capture the unit). • R1.2 and 2.2 All entities should use the same submittal form. Please delete the option for a Generator Owner to develop its own form. • R1.3… 90 days is too long for reporting data. Recommend 30 days for providing verification data. • VSL for R2 should mirror VSL for R1. Specifically R2 doesn’t mention submitting >120 days as R1 does. • Attachment 1: 1. specify that the AVR must be in service and in automatic controlling voltage if required by the TOP 2. If AVR is not required by the TOP, does the unit still have to test? Under the VAR-001 standard an entity may be exempted by the Transmission Operator from having a functional AVR. Under such an exemption the need for testing should not be required. • Attachment 2: move the check boxes to the top so that that someone looking at form knows immediately what type of audit was performed. • There should be VSLs in regards to going more than 66 months between verifications. • Periodicity should be captured in Requirements, not in the Attachment • If each test is done on different days, does each test have its own verification date? • Please clarify what footnote 1 of Attachment 1 is intended to describe with “normal” with respect to the unit’s normal expected maximum Real Power at the time of the verification. • Attachment 1, Section 2.1 states that during wind turbine and photovoltaic verification, 90% must be on line. This should read “with AT LEAST ninety percent of the…”
Yes
Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? This applicability criteria in this standard should be the same as the Compliance Registry requirements.
No
NERC is largely concerned with the declining frequency response of the Eastern Interconnection and this proposal seems completely at odds with that concern. The Planning Coordinator (or Transmission Planner) should definitely be allowed to request verification of selected governors. In addition to generators that have governor effect overridden by outer control loops (Distributed Control System, DCS) there may be a dead band within the governor. The Transmission Planner must be able to request verification of selected governor models that may fall outside of the standard. The question mentions Planning Coordinator but the standard itself is applicable to the Transmission Planner.
Yes
No

Yes
Requirement R4 is a direct violation of the Large Generator Interconnection portion of the ISO Tariff that requires generators to request permission and provide models prior to making changes to the equipment characteristics. As currently written, this appears to allow generators to submit models after making the changes. Such changes may have been detrimental to system performance and therefore need to be reviewed prior to implementation.
Yes
In requirement R2.1.1 what is meant by frequency excursion/reference change? This standard must require that all models provided are non-proprietary, otherwise a major reason (NERC MMG) for model collection will be undermined. This will prevent coordination of studies across regions which may undermine reliability. We are not sure if we have the correct version of draft MOD-027-1. In the “Differences also exist between MOD-026-1 and MOD-027-1” Section of this Comment Form, there are several mentions of Requirement R1 Part 1.x which we are unable to find in the draft standard. For example, Requirement R1 Part 1.2.1 in (5), R1 Part 1.3 in (6), R1 Part 1.4 in (7), and R1 Parts 1.1, 1.3, 1.4 in the “Compliance Elements for MOD-027-1” Section. Also, the referenced MOD-026-1 does not have the parts mentioned in this Comment Form. Is the background provided in this comment form incorrect, or are the posted versions of MOD-026 and MOD-027 out of date? In requirement R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by a many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping.
Yes
Yes, however the standard should not rewrite the Compliance Registry as attempted. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry’s wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity’s restoration plan. If the NERC standards become effective for non-material 9 MVA black start units those units will likely drop out of the program. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
Group
SERC Dynamics Review Sub-committee
Joe Spencer - SERC Bob Jones - DRS chair
Yes
Consolidating standards is beneficial
No
The DRS believes that the Transmission Planner (TP) should receive this information initially (which is what the standard currently requires).
No
This provides all the information needed to allow the TO to rate the machines at whatever ambient temperature may be needed. Per #2, the DRS recommends that TO be changed to TP. In attachment

1 item 3.4, the DRS recommends that “correction factor” be changed to “adjustment method,” to allow real power determination at multiple temperatures.
No
The use of sister units should be allowed by the standard. Also, verification should apply on the 75 MVA units, and above. Units smaller than this have very little impact on grid reliability.
Yes
These 4 points should provide adequate testing of the generator. The DRS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Yes
Yes
Yes
Synchronous condensers supply reactive power to the grid. Therefore, the Transmission Planner needs to know a verified capability for the device.
No
A 50 MVA criteria for synchronous condensers is not in the standard. The standard says 20 MVA. However, a criteria of 75 MVA would be a more reasonable number. Units smaller than 75 MVA will have little impact to the reliability of the grid.
Yes
No
The 20 % requirement is too restrictive. Any operational data should be allowed to be used if it is accompanied by engineering analysis which calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
The VSL for R2 is missing a needed component. The Severe category needs to include the following: "The Transmission Owner verified and recorded the Real and Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded." GO's should be required to provide expected values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Planners. Item 3.4 in Attachment 1 refers to Transmission Owner. It should say Transmission Planner to match Requirements 1 & 2. Only one verification is needed for sister (identical) units. The standard currently requires verification for all units.
No
The DRS agrees that the intended generating units would be covered by reasonable interpretation of the applicability section 4.2. However, the DRS recommends that footnote 3 be changed to read “The common transmission voltage level bus (i.e. 100 kV or greater) to which the step up transformer(s) is connected.” This more clearly includes “step up” transformers for some types of variable energy plants which may not be “generator step up” transformers.
Yes
Yes
We agree that it shouldn’t be included. However, it appears that there is an error in the question. Synchronous condensers cannot be used to control frequency. Was this a “cut and paste” error from

MOD-026?
No
No
Yes
For Requirement R1, the SERC DRS recommends that the time be changed from 30 calendar days to 90 calendar days. Relative to the time allowed for accomplishing other requirements, there is no benefit for only allowing 30 days for requirement R1. 90 days would allow for more communications between the requesting Generator Owner, the providing Transmission Planner and other entities (such as the software vendor or turbine manufacturer) to coordinate obtaining the necessary items listed in requirement R1. Additionally, 90 days would be consistent with the “more than 90 days” VSL level for this requirement. Relative to R3, bullet three, this covers the situation where predicted response does not match recorded response for three or more events. We suggest this be one or more events because significant events are so rare in the eastern interconnection. Relative to the VSL for R2, the first paragraph in the “Severe column” has confusing words "failed to provide the verified models no more than 90 days late." We recommend changing the words to "provided more than 90 days late". In multiple locations in Attachment 1, 730 days seems to be an excessive amount of time from capturing an event to sending documentation to the TP. We recommend a period of 180 days. In two places in Attachment 1, excitation control system is referred to. Shouldn't this be turbine/ governor control system?
Individual
Dan Hansen
GenOn Energy
Yes
Yes
Yes
The intent of the question is not well understood. The answer is complicated by the inability to replicate the system condition that will demand the unit operating limits, creating artificial lower limits under the test conditions.
Yes

No
Yes
No
No
Disagree strongly: It is overreach to make this a generator protection standard; the standard is not comprehensive enough to take on that task. As a result, the SDT has overstated the purpose and intent of this standard. Simple is better and appropriate. Purpose: To improve reliability through coordination of generator protection systems with unit/facility voltage regulating limiter functions and protection.
Yes
Yes
In some ways, the requirements are too subjective in determining what protection and limiters are subject to coordination. In other ways, the standard provides insufficient or contradictory requirements in defining how coordination is achieved, even for well established protection practices. It is difficult to define all-inclusive coordination principles with so many variables in a simple straightforward standard. As written, the standard is a compliance risk to the applicable entities based upon future arbitrary and subjective interpretation by compliance organizations. Vivid examples are provided in Attachment 1. Loss-of-Excitation Zones 1 & 2 does not “coordinate” with the Steady State Stability Limit. In the diagram of the generator capability curve, SSSL is reached prior to the Loss-of-Excitation protection, contrary to R1.1.1, requiring the protection to operate ahead of the SSSL. Also, Loss-of-Excitation Zones 1 & 2 exceeds the generator capability curve, and does not fulfill R1.1.1 that requires protection to operate before conditions exceed equipment capabilities. Other variables with indirectly relationships are subject to future interpretation. A generator stator may have overvoltage protection set at 118% with a 2 second time delay, allowing it to meet PRC-024-1 ride through capability. Overvoltage protection also has a correlation to field current limiters. To insure and demonstrate absolute “coordination” with a field current limiter under all circumstances, it may be necessary to reduce the field current limit. The move will be counter productive to system performance in most transient conditions, but may be required to insure “coordination.” The SDT should make specific requirements of defined scope rather than broad, subjective, and open-ended requirements, i.e. 1) Volts/Hz limiters shall coordinate with Volts/Hz protection, 2) Under excitation limiters shall coordinate with steady state stability limits and loss-of-field protection, and 3) field current limiters shall coordinate with field current capability. The standard should exclude statements that the protection must operate before conditions exceed equipment capability. It will be difficult to provide definitive evidence of compliance for the use of many protection elements on older equipment with no documentation of equipment capability to withstand conditions such as Volts/Hz. If a generating unit is rated for +/- 5% terminal voltage, how is the generator’s overvoltage withstand capability demonstrated to PRC-024-1 criteria. In a compliance world of absolutes, Generator Owners may not be allowed to use general “rules of thumb” when coordinating protection. In ways that are

counterproductive to reliability and equipment protection, Generator Owners could end up removing protection elements when it cannot be demonstrated that it operates before the condition exceeds equipment capabilities. Calculation of the steady state stability limit requires the transmission system Thevenin equivalent impedance. Therefore, it is necessary for the standard to require Transmissions Owners to provide Generator Owners this impedance within 30 days of request. Likewise, the allocated time for Generator Owners to perform coordination studies should increase by 30 days or more to 120 days. In R1.2, a five year coordination study interval is an unnecessarily short duration for generating units without significant changes in the generator protection or an AVR replacement. A company with 150 generating units will average 2.5 coordination studies per month on a non-stop continuous rotation. Ten years is a more appropriate cycle for a coordination study on a unit with no changes. The wording used to trigger an examination should be specific and defined, rather than the ambiguous and nondescript statement of "changes that are expected to affect this coordination." To meet compliance, it will be necessary to expend needless effort for the possible interpretations of "changes" that otherwise will have little or no impact for the intent or purpose of this standard. Suggest rewording R1.2, "Each Generator Owner or Transmission Owner shall verify the coordination indentified in Requirement R1 at least once every ten years or within 120 calendar days following modifications impacting coordination when the following activities occur: 1) a change in AVR limiters or AVR protection for over-excitation, underexcitation, Volts/Hertz, stator voltage, or field current, or 2) generator protection changes for stator voltage, loss-of-excitation, or Volts/Hertz protection." For only 30 days of differences (90 to 120), VSLs expand from Lower to Severe. Considering the justifiable allowance for 20% of the fleet to go 5 years without demonstrated coordination, the logic for the acceleration of severity over such a short time duration is not understood.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
No
Yes
No
PacifiCorp believes that the four points proposed by the SDT are adequate with respect to thermal and hydro generation units; however, the proposed points do not adequately take operating conditions for wind generation facilities into consideration.
No
First, PacifiCorp believes that over-excited reactive capability at rated Real Power verification should be performed on the same basis as for under-excited reactive capability and over-excited reactive capability at expected minimum Real Power output – that such data should be recorded as soon as a limit is reached. Second, this does not adequately take operating conditions for wind facilities into consideration.
Yes
Yes
Yes
Yes
Yes

No
No
Yes
Section 4.2 of proposed Standard MOD-025-2 contemplates the inclusion of large wind farms within the scope of the proposed standard, as it is applicable to generating units above individual and aggregate nameplate rating thresholds (as the commentary seems to indicate is intended). The specific requirements for verifying Real and Reactive Power capabilities, however, do not make any allowance for operating differences of wind generation units. If wind generating resources are to be included within the scope of this proposed standard, then the standard should include express allowances for verification methodologies that are applicable to wind generating units.
No
Yes
Yes
No
No
Yes
Section 4.2 of proposed Standard MOD-027-1 provides that units or plants with an average capacity factor greater than 5% over the last three calendar years, that also meet other characteristics, will be considered “applicable units.” However, the term “capacity factor” is not defined in proposed Standard MOD-027-1. Proposed Standard MOD-026-1, on the other hand, uses the term “Capacity Factor,” suggesting it is a defined term but without an accompanying definition in the NERC Glossary of Terms or otherwise. PacifiCorp believes that the Standards Drafting Teams should make the use of the term “capacity factor” consistent across all proposed standards and define the term as necessary for additional clarity.
Yes
Yes
Yes
Yes
No
Measure M1 in proposed Standard PRC-019-1 requires current evidence to satisfy the coordination requirements of Requirement R1, Section 1.1, plus one previous dated set of evidence demonstrating the latest coordination review has been performed within the intervals prescribed in Requirement R1, Section 1.2. The latter category of evidence may not be available immediately upon the effective date of this proposed standard. The implementation plan should clarify how this Measure will be addressed during the phased-in implementation schedule.
Yes
Yes
No

No
Group
NERC Staff
Mallory Huggins
Yes
No
Requirement R1, part 1.3 and Requirement R2, part 2.3 indicate that data is to be submitted to the Transmission Planner. We agree that the data should be submitted to the Transmission Planner, not the Transmission Owner. Further, we believe that the data should be provided to all entities that have need of the data, including the Transmission Operators and Reliability Coordinators who need the data for their operational planning and real-time models.
No
It is not necessary to specify a temperature for which submitted data should be adjusted because one temperature will not be appropriate for all regions or for all types of studies. Providing the recorded value and a temperature correction factor or correction table is appropriate.
No
While we agree that all units connected at voltage <100 kV need not be tested and modeled, any units >20 MVA and plants/facilities >75 MVA should be tested and modeled accurately regardless of interconnection voltage. The reliability impact of generating units is more directly related to unit capability than interconnection voltage.
No
Reactive Power capability is not a linear function of Real Power. The reactive capability curve and minimum excitation limiter settings for each machine should be used to determine the expected gross reactive capability.
No
Often, on larger units, temperatures do not stabilize within one hour. It is important for this test to assure that temperatures have stabilized and that the unit capability is sustainable, so the overexcited reactive capability test should be conducted for a minimum of two hours or until the temperatures have stabilized.
Yes
Yes
Although the penetration of synchronous condensers in North America is low, in most cases they are applied to address a reliability need, making it necessary to have accurate models of these devices for system studies. Although other devices may be outside the scope of this standard, accurate models are similarly necessary for devices such as static var compensators (SVCs) and static compensators (STATCOMs).
No
Section 4.2.1 indicates the standard is applicable to synchronous condensers greater than 20 MVA. We agree that the standard should be applicable to synchronous condensers greater than 20 MVA rather than 50 MVA.
Yes
No
We agree the standard should provide flexibility to the Generator Owner; however, the need for flexibility must be balanced against the need for valid models for system studies. Accuracy must be at least as stringent as required for market dispatch. When operational data cannot be verified within 5% of the expected value, an entity should be required to provide data based on staged testing.
No

No
Yes
The violation risk factors associated with Requirements R1 and R2 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 and R2 should include the operations planning horizon. The SDT should consider use of the word “verification” versus “validation” and assure that the term used in this standard is consistent with other standards.
No
We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
No
The standard should include a requirement that provides the Planning Coordinator the ability to request a review of any turbine/governor and load control or active power/frequency control system model for a unit not specified in the standard Applicability section. Accurate turbine-governor models can be critical to valid underfrequency load shedding assessments and other studies requiring accurate frequency response. This is particularly important for large units that operate infrequently, but are committed for critical operating conditions such as peak load or other times of capacity deficiency.
Yes
We agree that it is not necessary to validate synchronous condenser models in MOD-027 since synchronous condensers do not provide frequency response. However, the discussion supporting this question refers to verification of excitation control systems. Validation of synchronous condenser excitation control systems should be required in MOD-026.
No
No
Yes
It is not possible to accurately model system frequency response with valid models for only 80% of the installed system capacity. System frequency perturbations are experienced by and responded to by all frequency responsive generators, regardless of interconnection voltage. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per SDT estimates, this will assure accurate modeling for approximately 95% of installed capacity. The interconnection voltage is not relevant to frequency response and should not be a condition for applicability. We also disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions giving them lower capacity factors. However, those will also be the units loaded at lower levels, making them the units with head-room to respond, thereby making them critical to frequency response during those conditions. They may be of a lower priority in the implementation plan. The violation risk factors associated with Requirements R1 through R5 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R5 should include the operations planning horizon. In Requirement R2, part 2.1.1, it appears the comparison should be between recorded response and simulated modeled response rather than between on-line response and recorded response. Further clarification is necessary. In Requirement R4, when the

turbine/governor and load control or active power/frequency control system are modified as part of a planned project, the Generator Owner should be required to provide a revised model prior to placing the revised equipment back in service. In Requirement R5, part 5.2, the reference to negligible transients is not measurable. We recommend modifying this to ". . . results in a response that varies less than the numerical stability of the program used for the simulation." In Requirement R5, part 5.3, the introductory phrase "For an otherwise stable simulation" is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with "A disturbance simulation results in . . ." The SDT should consider use of the word "verification" versus "validation" and assure that the term used in this standard is consistent with other standards. Validation of models only every 10 years is far too long a period. Models should be calibrated as often as possible, preferably with every significant system frequency disturbance. Experience in the WECC region has shown that validation by observation against system events yields more accurate model performance than relying on a single staged test because the events provide for a wide variety of system conditions for the comparison. The background material suggests that more frequent validation against frequency events is impractical because of the scarcity of events. That is incorrect; there are several frequency events each year in all of the interconnections where frequency deviates beyond the short-term trigger limits set forth by the Resources Subcommittee, which indicate that generators should have exceeded the traditional deadband of ±36 mHz and responded. The initial completion of validation for all applicable units should be within 5 years, not 10 years. The 10 year time is excessive. Validation or calibration after a measured system event should occur within 6 to 9 months of the event, not 2 years. Experience in the WECC regions shows this to be sufficient and achievable.
Yes
No
The posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. We agree with the 20 MVA threshold in the posted standard.
Yes
Devices such as static var compensators (SVCs) and static compensators (STATCOMs) have equipment limitations, control systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser. Also, the standard must remain neutral as to the type of reactive resource, allowing for other technologies such as storage and demand-side regulation through electronically coupled loads that are relied upon for reliability purposes in the same vain as other reactive sources cited.
Yes
No
As written, the standard only addresses 80% compliance on generation and reactive sources that are not subject to regulatory approval. It appears that a section 5.2.5, similar to section 5.1.5, is missing from the Effective Dates section.
No
The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency. Further, Section G should address the system concerns described in Table 2 of the SPCS Technical Reference Document "Power Plant and Transmission System Protection Coordination," for the generator protection functions that must be coordinated.
Yes
No
Yes
The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the

generating unit, such as the list in Section G.This should be consistent with protection coordination described in the SPCS Technical Reference “Power Plant and Transmission System Protection Coordination.” Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions. Requirement R1, part 1.1.1: The standard emphasizes preventing tripping of generating units and generating facilities due to miscoordination. Another aspect of coordination is to coordinate the protections and controls to coordinate with the equipment capability. Without guidance or direction, the standard could have the unintended consequence of overly conservative settings that limit the ability of the facilities to respond to system disturbances, or inadvertently create a common-mode failure trip point across a generation fleet. Requirement R1, part 1.1.2: The word “check” is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as “Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment.” Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project, the Generator Owner or Transmission Owner should be required to verify coordination PRIOR to placing the revised equipment or settings back in-service. It is important to note that protection setting changes on the transmission system may necessitate generating unit protection setting changes which in turn require a review of coordination with the generating unit or plant voltage regulating controls. While coordination between the transmission system and generating unit protection settings is outside the scope of this standard it is important that this coordination is required by in a reliability standard. The examples emphasize steady-state limits and capability curves without mention of the short-term generating unit capabilities. Proper coordination should also apply to transient response of the generating unit and its associated limiters to meet the reliability objective of this standard. Focusing examples on steady-state coordination may be misleading and result in miscoordination for transient events. Of particular concern is the transient response of exciters in field-forcing during system disturbances; loss of reactive support from generation during such events can be catastrophic and lead to cascading. The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.
Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
The standard should allow the provision of ambient temperature during the verification be provided to the Transmission Owner as well as a correction factor to allow the Transmission Owner to adjust the Real Power data to a different ambient temperature if needed OR Real Power data submitted be temperature adjusted to some other than ambient temperature as requested by the TO.
Yes
The Applicability of this standard should be to BES Generating Units and Facilities. Section 4.2 should not restate components of the proposed BES definition.
Yes
No
To obtain more realistic rated real power and over-excited reactive power ratings, the minimum

verification time should be 2 hours or until temperatures have stabilized. For under-excitation, the test duration should be 1 hour.
Yes
Yes
To cover all configurations, the standard should also include and stipulate that synchronous machines that operate as generators at some times and as synchronous condensers at other times must perform a reactive capability test in each operating mode. This may be covered in Applicability 4.2.1 however the current wording should be modified to make this clear.
No
The 50MVA criteria in question 9 does not appear in the draft standard (only in the implementation plan). If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.
Yes
Yes
No
Yes
A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
No
No
Yes
Yes
-MOD-027-1 cannot be applicable to units dedicated as synchronous condensers since such units do not have turbine/governor and load control or active power/frequency control functionality installed. For generator units which can be operated as synchronous condensers MOD-027-1 already includes such units therefore reference to synchronous condenser operation is not necessary.
No
Yes
A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the elements that are included in the BES (and elements that are therefore applicable to this standard) according to provincial legislation and the NERC definition. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of this standard may differ for Canadian entities and entities under FERC jurisdiction.
Yes
-MH disagrees with the SDT's assumption that the majority of turbine/governor and load control functions will be verified through ambient monitoring. If both turbine/governor and load control functions as well as excitation control functions are to be verified through staged tests then having different effective dates for MOD-027-1 and MOD-026-1 introduces an unacceptable level of

complication in testing and documentation. MH recommends that the effective dates for both standards be identical and that MOD-026-1 effective dates be applied to MOD-027-1 to accommodate entities which will utilize more ambient monitoring than staged tests. -The SDT provides no information regarding testing and model verification which was completed under the regional guidelines (such as the MRO Generator Testing Guidelines) and the previous versions of the generator verification standards and which comply with the current version of the standard. With the amount of effort and costs which went into this exercise, MH proposes that such compliance information be accepted if completed within the past 10 years of regulatory approval of the proposed standards. Entities should not be penalized for lengthy SDT delays in developing these proposed standards. -For Section 4.2 “Facilities”, the section should refer to ‘BES Generating Units and Facilities’ instead of restating components of the proposed BES definition.
Yes
No
The 50MVA criteria in question 2 does not appear in the draft standard. If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.
No
Static VAr compensators do not belong in a generation standard.
Yes
No
-MH recommends that the effective dates for this standard be identical to MOD-026. This will allow entities to schedule all work and required outages simultaneously.
Yes
Yes
No
Yes
-The standard should take into account generating units whose capacity is determined based upon the run of the river where it may be difficult to test at design capacity. We suggest that an engineering methodology/calculation be acceptable for these units. -Wind generation should be excluded from the applicability of this standard or a calculation should be allowed due to the difficulty in testing wind units. -The SDT provides no information regarding testing which was completed under the regional guidelines (such as the MRO Generator Testing Guidelines) and the previous versions of the generator verification standards and which comply with the current version of the standard. With the amount of effort and costs which went into this exercise, MH proposes that such compliance information be accepted if completed within the past 5 years of regulatory approval of the proposed standards. Entities should not be penalized for lengthy SDT delays in developing these proposed standards. -The Applicability of this standard should be to BES Generating Units and Facilities. Section 4.2 should not restate components of the proposed BES definition.
Individual
Greg Rowland
Duke Energy
Yes
Yes, however need to define "Rated Real Power" so that entities are using a consistent basis for data reporting. MW validation is intrinsically connected to governor response issues and thus should be instead be combined with MOD-27 frequency response efforts and the following modelling parameters

defined and addressed: – Pmax • The continuous operating limit • The ultimate max emergency output. • Should there consider weather conditions (summer or winter, etc.). • PMAX associated with Transient stability – is it the same as for LF • Is this on the order of 105% or 110% or ??% of normal max loading Please clarify if real and reactive verification can be performed at different times.
No
The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data. Both the TPs and Transmissions Operations entities need to have accurate model information and the Operating studies are much more critical for BES reliability.
No
System models are used for reliability purposes beyond planning purposes, which are at best, an educated guess at what the system will look like out in the future. The real time and day ahead models are most significant for assuring reliable system operation. It would seem that if the TP needs model data different than the Transmission Operations needs, the 1st step is for them to define a technical basis for that data. Once that is done, then the GO/GOPs can develop numbers that match those conditions. Pmax will vary on ambient temp for some types of generation, lake temps for other types and hydo conditions for those units. Without a defintion of the data based on the studies to be performed, all the GO can do is guess. If the Q capacity is determined using a staged test, the ambient temperature during the test should be provided. The planning entity can adjust to other temperatures if they desire.
No
Obviously, all units which are critical to reliability should be included, but what is critical is dependent upon system configurations. The continent wide standard should specify the largest size units critical in an interconnection and then regional standards might tighten the number based on that region's need. The SERC region currently requires real & reactive verification only for units > 75 MVA (RFC uses 85 MVA). The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentialy identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).
Yes
We agree that four points are sufficient to provide a straight line approximation over a unit's operating range at points from Pmax and below, but additional consideration is needed for operation above Pmax. We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." The lagging capability curves have a break at rated pf. Trying to represent that with a single line with end point at Pmin and Pmax would eliminate a large portion of the available capability curve around rated pf. The leading capability might be more reasonably estimated by a linear assumption. Technically, nuclear units are base load plants as are some very large coal units and thus would not be expected to operate for any significant period of time at pmin, thus the term base load is more appropriate than nuclear for excluding testing at Pmin First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary."
Yes
Provided that the verification is accomplished through staged testing or through operational data review and a unit is capable of reaching the expected over excited capability, 1 hour should be adequate to determine if equipment temps that might limit capability are stabilized. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this

proposal in comments to Question 14).
Yes
We believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit (Graphic has been provided to the SDT). There needs to be standards on how model values are selected, such as, • The lagging capabilitiy values should be based on 90% of gross generator capability at minimum normal Hydrogen pressure minus aux system loads and xfmr losses • The leading capability values being modeled should be based on (UEL limiter setpoints as documented by PRC-19 coordination is probably appropriate).
Yes
No
As the draft is currently written, these two methods are understood to be allowed, but experience has shown may not be able to fully validate the available capabilites. We believe engineering analysis could be used in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies. The answer may be to test or operate as far as you can based on system voltage and then evaluate margin to unit thermal limts (Generator, Bus, GSUs, etc) and determine if you could reasonably have reached full capability if system conditions warrented the need.
No
We have model validation requirements but no definitions to what we are needing to validate to. The "expected value" is not clearly defined, so it is not possible to determine if 20% of this value is appropriate. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their underexcitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference our response to Question #10.
Yes
There have historically been regional differences in unit criticality size.
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) MVAR validation issues should be combined with generation FAC-8 issues to eliminate confusion that these seperate standards have caused. 3) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 4) We suggest revising Requirements R1.3 and R2.3. Data should be submitted to the TP at the next annual update provided on MOD-010 model data. 5) Revise attachement 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 6) It is noted that MOD-11 which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations). As a result, it is not clear that MOD-025 is achieving the reliablity purpose intended. 7) Since GO/GOPs do not always

model electrical systems, nor participate in interconnected system models groups such as the Master Model Working Group (MMWG), there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF is considering a collaboration to do so.
No
We are not convinced that wind plants need to be included at all due to a) the uncertainty of the wind availability during a frequency excursion and b) the transient nature of any contribution that the a wind turbine may be able to provide to correct or affect the frequency excursion. It is believed that the time frame of the frequency excursion will far exceed the wind turbine's ability to sustain a correcting action.
Yes
Yes
Not sure why this question is in the CF, other than it was accidently copied from the MOD-26 CF? Synchronous condendors are MVAR devices not MW devices and thus should be covered by MOD-26, not 27, if their dynamic response is signficant to grid reliability. Since they are typically applied in weak spots of the transmission system, it's difficult to believe they would not be critical by their presence.
No
No
Yes
1) Requirement 2.1.1 requires a comparison of the on-line response to the recorded response. The comparison needs to be between the on-line recorded response and the model simulated response. 2) The VSL table for R1 has time frames that don't match the Requirement R1 30 calendar day time frame. 3) The first paragraph of the Severe VSL for R2 needs to be split into two parts to form an additional OR statement which reads: "The GO failed to provide its verified model(s)" OR "The GO provided the verified model(s) more than 90 calendar days late to its TP in accordance with the periodicity timeframe specificed in MOD-027 Attachment 1." 4) The second paragraph of the Severe VSL for R3 is not grammatically correct and does not match the Requirement R3. Please consider changing it to read: "The GO's written response failed to contain one of the following: the technical basis for maintaining the current model, a list of future model changes, or a plan to perform another model verification." 5) For the Lower, Moderate, and Higher VSLs for R5, please consider placing "including a technical description if the model is not useable" within parenthesis to aide in understanding the measure. 6) For the second paragraph of the Severe VSL for R5, please consider rephrasing to read: "The TP provided a written response without including confirmation of all specified model criteria listed in R5, parts 5.1 through 5.3." 7) Attachment 1 contains multiple copy/paste errors (from MOD-026) and was difficult to constructively comment on due to these. 8) The frequency response of a generation unit is intrinsically connected to the Pmax values used in various system models (old MOD-24). These 2 validation efforts should be connected and the following modeling parameters defined and addressed: Pmax • The continuous operating limit • The ultimate max emergency output. • Should there consider weather conditions (summer or winter, etc.). • PMAX associated with Transient stability – is it the same as for LF • Is this on the order of 105% or 110% or ??% of normal max loading A graphic illustrating this point has been provided to the SDT.
No
See response to Question #2 below.
No
We feel that this standard is not applicable for solar facilities or induction type generators used in some wind farms. Several different exemption criteria are specified in the various GVSDT standards. We understand the distinction made for MOD-26/27 (100MVA) from the MOD-25 criteria (75MVA). The standard likely should be consistent with one or the other, rather than having a 3rd criteria (50MVA). For this standard, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit,

15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units ≤ 75MVA may be identified by a transmission entity as critical for BES reliability. Regional criteria are allowed to address these concerns to make requirements applicable to such units identified as critical for BES reliability in that region.
No
See the purpose of the standard. It's not clear why a generation protection/control coordination requirement would be applicable to non-generation resources, other than maybe synchronous condensors.
Yes
Yes
Yes
No
Electronic documentation of coordination efforts should be considered accecptible as long as a revision history is maintained. Past history is not significant to present/future reliability. Only the presentation documentation of coordinations is needed along with proof that the results have been implemented. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
Yes
There may be regional variations in regional critical size criteria.
Yes
1) In several places in the posting documents there is a discrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 2) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 3) Section 5.2.5 is missing from effective date in the draft standard. 4) R1.1.1.1 seems to infer that the 40 relays should be set inside the Capability curves and the SSSL. The 40 relay should be set inside the SSSL but may be outside the capability curves as it is intended to prevent a pole slip. AVR protective functions may be set to protect the capability curves.
Individual
Eric Ruskamp
Lincoln Electric System
Yes
Yes, but the verification periods should be different for Real and Reactive Power. It is not unreasonable to expect a Real Power verification test on an annual basis, as this data is usually available annually at some time when the unit is operated to serve load. It states the purpose of the Project 2007-09 Generator Verification is: “To ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Without annual operation to verify Real Power it appears difficult to ensure this objective with a high degree of confidence.
Yes
The Real Power Data should be adjusted based on temperature to indicate what the output for the generating unit would be for peak summer conditions for a summer peaking utility and peak winter conditions for a winter peaking utility. Humidity is also factor that affects the output of units with evaporative cooling as well as the performance of cooling towers. Previously as part of the Mid-continent Area Power Pool our utility was required to submit monthly capacity accreditation of the generating units that was adjusted based on the ten-year average of the high temperature for the peak load day of the month. For the summer months this provided a fairly accurate estimate of the

actual generating capabilities of the unit in the summer months. In the winter using the high temperature for the peak day was not quite as accurate, since the peak on the winter day does not usually coincide with the peak temperature for the day, but the ambient high temperature on these days is usually quite low. Even in the shorter months the output data may be beneficial to the Transmission Planner when large units in a region are out for maintenance. It is questionable as to how easy it would be for the Transmission Owner to apply the correction factors to other ambient temperatures if they are only given the temperature at the time of verification test. For gas turbine units without some form of inlet cooling the output may vary by as much as 30 percent from summer to winter ambient conditions. This is a significant amount of generating capacity.
No
The definition of “expected value” needs to be more clearly defined as it is somewhat unclear. The verification should probably be within at least 5% of the expected output of the generating unit for a given ambient temperature, rather than 20% as stated in this draft. For a simple-cycle gas turbine the real power output for the verification test would in most cases be greater than what it would be for summer peak conditions due to the higher generator output that typically occurs with these units as the turbine inlet temperature decreases. It is usually desirable to test the unit with the same conditions that the unit will be most needed. For summer peaking utilities this would be with reasonably high ambient conditions. When only recording real power data it is usually not that difficult to recordthe data in the summer when the units are already operating to serve the load. The coordination to record reactive power data at this time may be more difficult.
Yes
Under the Applicability Section, 4.2 Facilities, the “applicable units” are stated to have an average capacity factor greater than 5% over the last three calendar years and that the “majority of industry agreed with the standard MOD-026-1 5% capacity factor threshold” (Background Information: “Standard MOD-027-1” - #3). LES is concerned that the industry builds power flow models for future summer peak conditions, and therefore, LES is not convinced that the capacity factor threshold of less than 5% is a good indication of what units are on-line in these future models. Therefore, the goal for verification of the dynamic models associated with 80% or greater of the connected MVA per Interconnection may not be achieved. LES believes that a check (i.e., survey) of the ERAG MMWG models would be a good indication of whether or not the capacity factor threshold satisfies this objective.

Individual
Jose H Escamilla
CPS Energy
No
The Transmission Planner is the appropriate entity to use the data.
Yes
Generator owner should perform the correction and determine the temperature value.
Yes
Yes
No
30 minutes should be sufficient time to verify capability.
Yes
Yes
Group
Public Service Enterprise Group
John Seelke
Yes
No
MOD-025-2 requires that data be submitted by GOs or TOs to their respective Transmission Planner

(R2.3). It should not require that it be submitted to the Transmission Owner as the TO has no need for this data.
Yes
We believe that the Real Power data submitted should be corrected to a temperature specified by the entity that requires the verification of Real Power capability. That entity is probably the Resource Planner or the Planning Coordinator– see the Functional Model, version 5 posted at http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf. For Generation Owners that belong to Regional Transmission organization that has a reserve margin criterion, it is probably registered as a Resource Planner and Planning Coordinator. For example, PJM, NYISO, and ISO-NE are each registered as a Resource Planner and a Planning Coordinator.
Yes
No
For clarification, Attachment 1, paragraph 2.2 does not require Reactive Power capability verification for wind and photovoltaic at minimum Real Power output. It also appears that Nuclear Units are also exempt. “Nuclear Units” has the term “Units” capitalized, but it is not in the NERC Glossary and should probably be lower case. We suggest that R2.2 be redrafted as follows: “Verify Reactive Power capability of all generating units other than nuclear, wind and photovoltaic for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they could normally be expected to operate. In addition, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. This would require a change in paragraph 2.1 For other units, these points are acceptable.
Yes
The drafting team should provide the rationale for the one hour minimum for over-excited reactive capability.
Yes
This documents the system conditions and unit conditions when limits are reached.
Yes
A 50 MVA minimum size for synchronous condensers was not found in the proposed standard – see paragraph 4.2.1 which has a 20 MVA minimum. Whether the limit was intended to be 50 MVA or the 20 MVA limit stated in the draft, the SDT should provide a justification of basis for that MVA threshold. The impact that such smaller units would have on the BES is not substantial enough to justify requiring their inclusion in this standard.
Yes
No
Attachment 1 is unclear as to the implementation of the 20% requirement. Paragraph 2 states “Operational data from within the year prior to the verification date is acceptable for the verification as long as it meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:” As written, it appears that the 20% only applies to operational data “within the year prior to the verification date.” Does the 20% apply also to staged tests? If not, why not? Paragraph 5.2 in Attachment 1, regarding operational tests, is also relevant: “If data for different points is recorded on different days, the Generator Owner shall designate one of the dates as the verification date, and report that date as the verification date on MOD-025- Attachment 2 for periodicity purposes.” Is the SDT proposing to comingle operational data from one-year prior to the verification date as long as it is within 20% of the expected value? If so, what value would be reported – the test data that may be up to 20% higher or lower than the expected value or the expected value?
No
Yes

We have listed several concerns and questions below: a. We believe that Reactive Power capability at minimum Real Power output needs to be verified when a unit is installed and only verified thereafter when the generator itself is modified. Performing such tests will be difficult to run due to system voltage limitations at minimum Real Power generator output. This would require a modification or Attachment 1, paragraph 2.2, and paragraph 5. b. For the VSL's for requirement R2, the last paragraph of a Severe VSL should be modified as follows: "The TO verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days from the date the data was recorded." c. The comments below reference Attachment 1. i. Paragraph 2 and its subparts would be more easily understandable if companion tables were provided that summarized the information. At last two tables would be helpful – one for traditional dispatchable resources and one for variable resources. ii. In paragraph 3, whether the verification is staged or operational should be provided. iii. In paragraph 3.2, the requirement to supply the voltage schedule provided by the Transmission Operator would not appear to be applicable for a staged test. Trying to test Reactive Power limits while maintaining a prescribed voltage schedule in not practical.
No
Yes
Yes
No
No
Yes
Nuclear units are often prohibited by their NRC licenses from having their governors engaged for frequency response. Since the Purpose of the standard is to "accurately represent generator unit real power response to system frequency," nuclear units with the restriction described above will have no response. These units should be explicitly exempted from the standard in the Applicability section.
Yes
No
The question and the standard contradict each other. The standard states that it applies to "synchronous condensers > 20 MVA" not "rated > 50 MVA. We do not agree with the threshold MVA applicability for generators. Field testing and industry history do not warrant the need for such a low MVA threshold. We suggest that the threshold be for larger units (rated > 500 MVA) that have the ability to significantly impact BES reliability. The resources required to apply this standard to smaller units compares to the benefits to the BES and the GO are generally not justified in most regions. However, it can be argued that smaller units can have a significant impact on the BES, especially in weak systems. Therefore, we recommend that an inclusion criteria be developed that would require units in such regions to be included.
No
First, the inclusion of "variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites)" was not noted in the standard. Second, we do not believe that including other static reactive resources that are not located at generating sites would materially impact reliability
Yes
Yes
Yes

Yes
Yes
Yes
The SDT should review R1. As it reads now, the phrasing of the first paragraph makes it difficult to understand what equipment is included for generator units and what is included for synchronous condensers.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We support this approach. The real and reactive power capabilities are related and hence having them addressed in one standard would enhance verification efficiency.
No
(1) The receiving entity cited in this question (Transmission Owner) seems different than the entity indicated in the standard (Transmission Planner). If it is not a typo, then we may be missing something. Regardless, we commented previously (on MOD-024-2) on a related subject in which we indicated that given the purpose of the standard, which now reads: “To ensure that planning entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”, we believe that the data is used for planning assessments that could entail both resource adequacy and transmission reliability, and may even include short or near-term transmission reliability assessments. In view of the facility ownership and potential users, submitting the data to the Transmission Owner does not seem to be logical from the following standpoints: a. The TO does not own the generators and may not actually use the data at all if it does not perform transmission planning assessments; b. The Transmission Planner is the entity that conducts transmission planning assessments; c. Other planning entities that use this data are the Planning Coordinators and Resource Planners. For the above reasons, a more logical entity to receive this data and be the one that requests for data is made by other entities that have a need for the data such as Transmission Planners, Resource Planners, Reliability Coordinator and Transmission Operator, would be the Planning Coordinator. We suggest to change Transmission Owner to Planning Coordinator. (2) And also in view of the potential use of this data, we suggest the purpose of the standard be reverted back to its previous version: “To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.”, or be revised to: “To ensure that [the word planning removed] entities have accurate generator Real and Reactive Power capability data when assessing Bulk Electric System (BES) reliability”.
No
(1) We do not support the notion that a Transmission Owner has the technical expertise to adjust a generator’s real power capability to reflect a difference in ambient temperature. If anyone, it should be the Generator Owner. (2) There seems to be little value in reporting the ambient temperature for the purpose of making adjustments to measured Real Power capability since it is only one of the several factors that could affect the real power output of a generator. (3) Notwithstanding the concerns expressed above, to make such an adjustment with some degree of accuracy, the responsible entity needs to have the information on that capability which corresponds to the ambient temperature for which the adjustment is to be made. It thus suggests that a capability-temperature curve be first established to provide credible references, implying that the Generator Owners must conduct a series of verification tests under different ambient temperature conditions. This is overly cumbersome,and creates unnecessary burden to the GOs. We suggest that this requirement be removed from Attachment 1.
No
The Applicability section is not clear enough to expect consistent application. When the facility that makes the connection at 100 kV or above is not owned by the Generator Owner (e.g. a Distribution Provider might own this facility) the present expression of the standard will lead to inconsistencies. Facilities with identical electrical characteristics may or may not be subject to this standard only because of the structure of the ownership of assets. To address this, we propose revising section 4.2

by removing the condition for interconnection at 100 kV and above and aligning with the standard's purpose: 4.2.1 Individual generating unit or synchronous condenser > 20 MVA (gross nameplate rating) considered in BES reliability assessments.. 4.2.2 Generating plant/Facility > 75 MVA (gross aggregate nameplate rating) considered in BES reliability assessments. 4.2.3 Blackstart units, regardless of size that are included in a Transmission Operator's restoration plan.
No
One of the purposes of Project 2007-09 is to ensure that generator models accurately reflect the generator's capabilities and operating characteristics. To achieve this, it is important that at least the minimum data requirements of entities that require these data are satisfied. This includes verifying the generating unit's capability curve or at least that portion of the curve between its minimum and maximum real power capability. We therefore recommend including a new bullet 2.3 in MOD-025 Attachment 1 similar to bullet 2.1 that requires verification of Real and Reactive Power capability of all generating units at maximum over-excited and under-excited reactive capability at maximum gross Real Power capability (PMAX) where this is different from the generating unit's rated gross Real Power capability. The additional data points provided by this measurement (i.e. Qmax and Qmin at PMAX) will allow for a more complete verification of the generating unit's capability curve. Footnote 1 of MOD-025 Attachment 1 seems to use "rated gross Real Power" and "maximum [gross] Real Power" interchangeably. In general these two ratings may be different. We suggest deleting the footnote.
Yes
Yes
Yes
The standard should also be applicable to static var compensators and similar equipment used in reliability assessments of the BES.
No
There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Yes
No
We have difficulty interpreting the 20% in Item 2 of Attachment 1, which says: "Operational data from within the year prior to the verification date is acceptable for the verification as long as IT (emphasis added) meets the criteria in 2.1 through 2.5 below and is within 20% of the expected value:" We interpret that the "IT" refers to the operational data. As such, we do not understand the "within 20% of the expected value". Does it mean the generator's real power output during the period from which operational data was collected must be within 20% of the generator's declared or name plate capability, or what? We need clarification, and suggest a revision to this Item 2 to provide the clarity. As written, we are unable to comment on the acceptability of the 20%.
No
No
Yes
In our previous comments, we raised a concern over the detailed requirements in Attachment 1 which in our view are overly prescriptive. Specifically, the requirements listed in Item 3 of Attachment 1 are too detailed, and some of the items listed in 3.1 to 3.6 are not needed or relevant to the provision of verified data for modeling or BES reliability assessment, but they create unnecessary administrative burden. For example, what would be the use of voltage at the high side of the generator step-up and/or system interconnection transformer(s) and the tap settings of these transformers in the application of the recorded real and reactive capabilities to modeling and reliability assessments? And what would be the required actions if the voltage levels and/or the transformer tap setting in the loadflow model or in real time are different from the reported values? Imposing the reporting requirement without a clear statement of the intended use, with justification, is unnecessary and

should be dropped. Further, we request clarification regarding the phrase “at the end of the verification period” in 3.1 and 3.3? Does it mean the time when the verification test ends, i.e. at the end of the 1-hour period referred to in Attachment 1, bullet 2.3? If the verification is provided by operational data, what would constitute “the end of the verification period”? We believe Attachment 1 needs only to specify the sustainability (Items 1 and 2) and the periodicity (Item 5). We also respectfully disagree with the SDT’s response to our previous comments on Attachment 1. The SDT’s view that (excerpt from Comment Report) “The SDT believes that attachment one does not contain requirements but provides clarity to the Requirements of the Standard.” is incorrect since it is clearly indicated in Requirement 1.1 to “Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1.” According to the general rule for NERC standards, an attachment is a part of the standard that must be complied with, and hence any items contained in an attachment are mandatory requirements. With that understanding and with the way Attachment 1 is included in Requirement 1.1 that the items in Attachment 1 are not there for clarity but are requirements that must be complied with, we urge the SDT to remove the entire Item 3 from Attachment 1 as the information required in that item does not add to the intended use of the verified data. We do not have the same concern over Attachment 2 since it is made clear in Requirement 2.2 and in the Attachment itself that use of other forms is acceptable and hence use of the diagram is not mandatory. In Attachment 1, step 2.4 seems to be inconsistent. For the over-excited check, record should be taken at min. and max. real power output (i.e. it should state... data required in 2.1 and 2.2.) The table in Attachment 2 should be improved to match data to be recorded in Attachment 1 (i.e. there should be two columns for MVAR to record lagging and leading reactive power for a given MW). MOD-025 Attachment 1 bullets 2.1 and 2.2 should stipulate that Generator Owners and Transmission Owners conduct verification at generator terminal voltages as close as possible to rated terminal voltage. Finally, the standard should use SI units (e.g. active power not real power, Mvar not MVAR).
No
No, we are not aware of any, but the Applicability Section of the draft standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the “generating units” suffice to generally include all types of energy resources?
No
We do not agree with this approach. Currently, the applicability threshold of nameplate rating greater that 100MVA is too high. The combined performance of many units smaller than the threshold identified in the applicability section will have a material effect on the system frequency response. Even if the standard leads to the provision of useable model to the Transmission Planner for the applicable generating units, without sufficient good models, it might not be possible to meet the goals of accurately represent generating unit active power response to system frequency variations and predicting system frequency response to contingencies. We repeat the concern we expressed in our comments to MOD-025-2 related to the applicability criteria “connected at the point of interconnection at greater than 100 kV.” This condition will lead to the exclusion of units that are material in dynamic simulations and to which the applicability should extend. Also, we wonder whether the inclusion of Planning Coordinator in the question is a typo or the standard is missing the Planning Coordinator as an applicable entity. Please clarify.
Yes
No
No
Yes
We do not agree with some of the requirements. i. R1: Standards should stipulate the “what’s” not the ”how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”. Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be

complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process. ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). Another possibility would be to remove this phrase altogether since the Transmission Planner would in any case have to declare the model “useable” pursuant to Requirement R5. iii. R5.3: It stipulates as a criterion that a disturbance simulation results in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. iv. We decide not to comment on the Measures and other compliance elements at this time in view of the comments, above.
Yes
No
There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
No
The SVCs serve quite different purpose and react to system conditions quite differently compared to their generator/synchronous condenser counterparts. Further, SVCs do not “trip”, per se, they vary their reactive outputs including going to and crossing 0 MVar and hence some of the interactions between the device and its protection systems in the case of generators/synchronous condensers are not applicable to SVCs.
Yes
We do not have any real issues with the purpose statement; however, we offer an alternative to add a bit more positive spin (as opposed to preventing tripping): To improve the reliability of the Bulk Electric System by ensuring proper coordination of generating unit/facility voltage regulating controls and limit functions with generator capabilities and protection system settings.
No
We interpret the wording “shall retain the latest and the prior evidence of compliance with Requirement R1, Measure M1” to mean the evidence for the last and the one before last compliance assessments. We question the need to keep the two sets of evidence. Keeping only the evidence for the last compliance assessment would suffice.
No
Yes
1. The standard introduces a local definition: “in-service”, that is subject to interpretation. Does “in-service” mean: - Installed but may or may not be put to service (e.g. mothballed)? - Installed and can be put to service at any time? - Installed and on-line? Generators/synchronous condensers will have a reliability impact only when they are connected to the grid (put on-line). However, the timing of these facilities to be put on-line is at the discretion of the GOs and perhaps under some conditions specified by other entities such as the TOP or RC. It is thus conceivable that installed facilities can be

put on-line at any time. To ensure proper reliability performance, we suggest to change “in-service” to “installed” to make sure the facilities meet the standard requirements if and when they are put on-line. 2. R1.2: The wording: “verify the existence of the coordination” does not drive home the intent of ensuring the settings are coordinated and reviewed once every 5 years or as changes occur. We suggest to change R1.2 to read: “shall review and revise as necessary the coordinated settings identified in Requirement R1 at least once every five years or within….”
Individual
Karen Alford
Gainesville Regional Utilities
Yes
Yes
No
Yes
Yes
No
We suggest 30 minutes. While it may take an hour to reach full stabalized temperatures the probablity of being called to peform form greater than 30 minutes is remote.
Yes
Yes
Yes
Yes
Yes
What is defined as the "expected value?"
No
No
No
No
Yes
Yes
No
No
No

Yes
Yes
No
Yes
Yes
Yes
No
No
Individual
Kirit Shah
Ameren
Yes
No
Both the Transmission Owner and Transmission Planner should receive it.
Yes
The ambient temperature at which the testing is performed would be an important data item. Because of greater familiarity with the equipment and its capabilities, any temperature adjustment to arrive at a different specified real power value should be performed by the Generator Owner. The Transmission Owner/Transmission Planner, who would be performing system modeling and study work, would be the entity most appropriate to specify temperature values for which temperature adjustment factors would be determined. Capabilities at different ambient temperatures need to be provided to meet the modeling requirements of the MMWG, and that the GO and TO should agree on what ambient temperatures to assume for the temperature adjustment.
No
The allowance for exemption of sister units should be permitted. Only one verification for sister units should be required. Testing for units less than 75 MVA should not be required, as these have little impact on grid reliability.
No
While the testing regimen for the generator owners should not be made unduly burdensome, the four point test, if used to provide a straight line approximation of the generator capability, could result in somewhat more conservative reactive power operating limits for other real power levels as compared to a generating unit’s published capability curve. The accuracy of the straight line approximation would vary on a generator-by-generator basis.
Yes
No
(1) From transmission perspective: If a plant limit is encountered in the testing, and it is a hard limit not to be exceeded, then the capability at this limit should be recorded. If a limit is identified on the transmission system such that the testing cannot be completed, then the capability should be noted but this would not be a firm limit. (2) From GO perspective : Our testing people won't know if the

transmission system is causing the limit because they aren't allowed to "see" the transmission system. Second, they are not allowed to test at time of seasonal peak because their testing may jeopardize the availability of the unit and testing during the fall and spring will mean higher voltages and frequently some type of testing limit is reached. Engineering calculations and justification should be allowed. Finally, we thought the 20% "margin" was to allow for these unavoidable risk restraints on testing the units. If a plant limit is encountered in the testing, then the capability at this limit should be recorded. However, it is unclear how this data, and the 20% margin, should be used in the verification process. We request the SDT clarify how data readings within the 20% margin should be used to determine the Real and Reactive capabilities of a generator or plant.
Yes
No
The size of synchronous condensers to be verified should be consistent with generator sizes which need to be verified. Testing for units less than 75 MVA should not be required.
No
While these two methods are acceptable, there is not enough flexibility included to allow for engineering support if necessary.
No
While the 20% margin is appropriate and appreciated, it is unclear if verifying the output of a generator at 80% of real rated output will satisfy regulator rating requirements at the time of seasonal peak. Thus, from the user of this data (e.g. planners), this % is too great. From the generator owner and testing personnel , this % makes sense and seems appropriate. We would suggest the SDT provide basis for this % and a guidance how it should be used for all conditions.
No
Yes
There may be a conflict with MISO Module E as it relates to duration of the testing, e.g. one hour versus longer than hour duration.
Yes
(1)If a demonstrated value is less than the corresponding expected value, then the generator owner should be required to provide calculated values for reactive capability in addition to the demonstrated values (this should be included in R1). Without this, the data is useless to the Transmission Owners for system modeling use. (2) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (3) We understand the 20% and 10% variances allowed in the draft are for testing purposes. However, it's unclear how they should be used. For example, are they relative to the results at time of seasonal peak, or just maximum output at the time of testing? (4) Notes 1 and 2 should be Requirements. It is difficult to determine how compliance with footnotes will be audited. (5) Engineering judgement should be clearly allowed when meter data (for example no meter at the high side of a GSU), auxiliary data, etc. is not available as required in Attachment 1. (6) Sister Unit exemptions should be allowed for generators that are essentially identical and operated in an identical fashion.
No
Yes
Yes
The question does not appear to be worded correctly. Draft Standard MOD-027-1 deals with turbine/governor and load control, rather than excitation control systems.
Yes
(1) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (2) R4 of the Draft references footnote

5. It appears this footnote is overly broad and requires editing to precisely identify equipment systems that can truly impact system reliability. This footnote should be edited so it becomes either a new Requirement or a new set of sub-requirements. No other systems should be included.
Yes
Yes
Yes
Question should be directed at transmission planners. I would believe the static VAr compensators are required for system voltage support, similar to synchronous condenser or generation.
Yes
Yes
Yes, only if settings need to be verified. No if testing needs to be done to verify settings.
No
(1)Volts per hertz and stator overvoltage protection are more applicable during unit start-up, not running conditions, where the system maintains the voltage and frequency. These should be eliminated. (2) The standard needs to be clear on what relay elements need to be included if enabled. (3) The standard needs to be clear on how to plot the diagrams to incorporate operating voltage. For example the generation is most stable while maintaining maximum permissible voltage and producing the most VAr's possible. Therefore should the plot be at maximum voltage of 1.05pu. (4) It would be helpful to have some reference for where the development of the Steady State Stability Limit equations in the draft standard could be found. None could be found on the NERC website. We are concerned that the method proposed for calculating steady state stability limits does not include sufficient conservatism.
No
Retaining studies for 10 years seems unreasonable and could lead to confusion. Retaining data from previous audit seems reasonable to assure studies are being done every 5 years. Regarding R1.1.2, in order to limit the need to take unnecessary outages, which may be required to verifying settings, verification of settings should be limited to a one time only, upon installation or setting change.
No
Yes
(1) Standard needs to be more specific and clear on what evidence is need for 1.1.2. (2) Violation Severity Levels seem arbitrary and need to be reviewed, considering the standard is giving four years to be 100% complete. The system is presently operating with few if any miss-coordination on these protection systems. (3) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (4) R1.2 states there must be verification of coordination within 90 calendar days following "...identification or implementation..." of systems or changes. There is typically an enormous difference between the "identification" and the "implementation" of these systems. Would the SDT please clarify what is expected? (5) Sister Unit exemptions should be allowed for plants with multiple identical units that have identical equipment and control systems. (6) This Standard should only apply to generators with a nameplate rating of > 75 MVA and a connection to the interconnected transmission grid > 100 kV. (7) The use of "Stead state stability limit" in bullet #4 in R1 and the use of the phrase "...system steady state operating conditions." in R1.1.1, seem to conflict. Is the term in R1 intended to represent system conditions AFTER an N-1 contingency, or during N-0 conditions?
Group
SERC Generation sub-committee
Joe Spencer - SERC staff
Yes
Please clarify if real and reactive verification can be performed at different times.
No

The TP or the PC (PA) is the entity needing the data, rather than the TO. R1.3 and R2.3 specifies that the TP be given this data.
No
Providing the ambient temperatures at the time data is collected is acceptable. However, there is no simple correction factor that can be provided. Reactive capabilities under different conditions cannot be assumed to be the same.
No
We believe that Section 4 Applicability (4.2.1 and 4.2.2) for this standard should be revised to match the Section 4 Applicability for MOD-026-1 and MOD-027-1. NERC is focusing on standard requirements that have significant impacts on system reliability. Including smaller units without demonstrating their criticality to the system appears inconsistent with this philosophy. Verification for smaller units should only be required if technically justified by the Planning Coordinator as specified in 4.2.4 of MOD-026-1. The use of "sister" (essentially identical) units should be allowed by the standard (as is allowed in SERC's current MOD-025 procedure). Independent verification of essentially identical units should not be required. Blackstart units (4.2.3 of Section 4 above) should not be covered under the MOD standards. They are covered under the EOP standards (EOP-005-2).
No
Although we agree that four points are sufficient to provide a straight line approximation over a unit's operating range, we don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. Finally, for units where verification of multiple points are needed, the analytical approach to verification,discussed in our responses to Questions 10, 11, and 14, serves this purpose very well. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, The GS does not believe that verification for leading capability should be required where operational practices preclude operation in a leading mode.
Yes
Provided that the verification is accomplished through staged testing or through operational data review. This requirement would not apply if the verification is accomplished using an engineering analysis method (see this proposal in comments to Question 14).
Yes
But, we believe that there is little value to a minimum load, vars-out requirement. Also, it will be difficult to achieve since the system usually has minimum VAR output requirements when operating at minimum load. Experience has shown that a large unit cannot reach the full available lagging (many times) or leading (most times) reactive capability values due to voltage limitations. That does not mean that that capability is not available. This is exemplified by the testing of a large fossil unit below (attempted to include graphic).
No GS comment
No
It is noted that this criteria is not consistent with the criteria for generators or with 4.2.1 of the draft standard.
No
As the draft is currently written, these two methods are understood to be allowed. However, we believe a third alternative, engineering analysis, is needed in order for GOs to be able to verify generating unit reactive capabilities that are suitable for transmission system planning studies (See our Comment 2 under Question 14 for additional discussion on the verification methods.). It is proposed that Requirement R1.1 be re-written as follows: "Verify the Real and Reactive Power

capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with either Attachment 1 (staged testing or operational data) or by a new Attachment 3 (addressing engineering analysis)." The SERC GS could provide a template for this. Requirement R1.2 could then be qualified to be limited to reporting the results from staged testing or the use of operational data, and a new R1.3 could be inserted to require suitable reporting of the results from an engineering analysis. The time horizon of the two requirements in this standard are Long-Term Planning. MOD-025-2 does not have to focus solely upon operational testing to determine capabilities used for planning entity models. It is noted that TOP-002-2a R13 now requires the GOP to perform real and reactive capability testing at the request of the BA or TOP. The test can be specified if determined to be necessary by the BA or TOP.
No
Since the "expected value" is not clearly identified, it is not possible to determine if 20% is an appropriate value. Furthermore, if the "expected value" is the "D curve" for lagging Vars, we believe this is not a realistic expectation since operational data for most generating units does not approach 80% of the "D curve" value in normal operating conditions (or even in staged testing based on our experience). A recent survey of the SERC region has shown that only 34% of 85 generators surveyed performing staged Q production tests could reach 80% of their D curve lagging Q capability. The same survey showed that only 19% of 32 generators surveyed performing staged Q absorption tests could reach 80% of their under excitation limit (UEL) characteristic setting. Therefore, the "within 20% of the expected value" requirement should be deleted. If an engineering analysis (which uses operational data for analytical model confirmation) is allowed as an alternative verification method, the 20% tolerance given above is not needed. Reference comment 2 under Question 14 for additional discussion on the verification methods. Any operational data should be allowed if accompanied by engineering analysis that calculates appropriate expected limits. This will be more useful to the Transmission Planner than a value from operational data within 20% which does not give the appropriate expected limit.
No
No
Yes
1) This requirement will require units that normally do not run or have a very low capacity factor to be verified. Please add a provision for excluding these requirements for units that do not regularly run, similar to other NERC standard exemption requirements. 2) The standard needs to allow the inclusion of engineering analysis (with operational data) to supplement or replace testing when appropriate (see comments to question #10). It is noteworthy that the original NERC Board Approved version of this standard states in requirement R1.3 that acceptable methods for reactive capability verification "include use of commissioning data, performance tracking, engineering analysis, testing, etc." This represents the "allowance to use of all the tools in the toolbox" approach which is appropriate when no single tool is sufficient to accomplish the stated reliability objectives, consistent with the FERC Acceptance Criteria of a Reliability Standard (reference Paragraphs 321, 324, 328, 332). This approach is reflected in the SERC regional procedure for MOD-025-1 which was developed by a joint transmission-generation task force. 3) The 5 year test interval should be changed to a 10 year interval since there is a provision for re-verification with an associated 10% system change. 4) In R1.2 and R2.2, the phrase "same information" is used, while in M1 and M2 the phrase "equivalent information" is used - we suggest changing R1.2 and R2.2. to match the M1 and M2. 5) Specifying Normal Operating H2 pressure in Attachment 1, section 2.5 may not produce the desired maximum Q cap results - consider changing "normal operating " to "maximum sustainable (within design limits)" 6) In Attachment 1, section 2.2, we suggest changing "they could normally be expected to operate" to "they are normally expected to operate". 7) We suggest revising Requirements R1.3 and R2.3 to read: "Submit the capability information to its TP within 90 calendar days of completion of the verification." to clarify these requirements and to make them consistent. We also believe 90 days will create an undue hardship for GOs who own a large number of generators and thus we also request that this requirement be revised to allow additional time when authorized by the TP or PC. 8) The first paragraph of the Compliance Data Retention Section D 1.2 is difficult to understand. Please simplify using multiple sentences, if possible. 9) In the VSL table for R1 and R2, we suggest changing the

phrasing "from the date the data was recorded" to "from the verification date" each time it is used (7 times). 10) In the VSL table for R1, both the first and fourth items are not needed in the list of the four items which make up the OR statement. It is sufficient to measure if the data is more than 30 days late to be categorized as Severe. 11) In the VSL table for R2, we suggest replacing the second item in the list of the two items which make up the OR statement to match the corresponding item in R1 relative to the tardiness of the submission to the TP greater than 30 days late (> 120 days total). 12) Revise attachment 1 section 5.1 and 5.2 to change “last more than 6 months” to “last more than 1 year,” to align with the typical long-term planning horizon. 13) It is noted that MOD-11which is supposed to clarify modeling data requirements has not yet been completed and approved. Yet MOD-25 is requiring verification of this data. It is also recognized that generator verification methods are producing results that are not being directly used in the models (due to various operating or system limitations) .As a result, it is not clear that MOD-025 is achieving the reliability purpose intended. 14) This standard establishes a periodic generator testing regime which, when implemented on a large number of generators, creates a continuous state of testing across the BES. We question if this approach really improves the reliability of the BES. The use of normal operational data, supplemented by analysis, represents a better approach to verify reactive capability for most generators. Targeted testing can then be used on a limited basis.
Group
ACES Power Members
Jason Marshall
Yes
No
The requirements appear to correctly show the data being submitted to the TP. However, Transmission Owner in 3.4 of Attachment 1 should be Transmission Planner.
Yes
Yes

No
Yes
Yes
Yes
No
It is not clear how this standard is applicable to variable static reactive resources located at asynchronous generating facilities. They do not appear in applicability section.
Yes
Yes
No
The data retention for M1 may not be consistent with NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC appears to require some level of evidence for the entire audit period.
Yes
In part 4.2.3 of the Applicability section, the phrase “regardless of size included in a Transmission Operator’s restoration plan” should be struck. It is redundant with definition of Blackstart Resource.
Individual
Rex Roehl
Indeck Energy Services
No
Testing will be more difficult if combined.
No
TP
No
No temperature adjustment can be done reliably with real and reactive power. Real power may be adjusted, but not with reactive. Generator can make the adjustment if there is a nationwide standard. If not, then regional standards will be required to specify the values.
No
Some standards need to apply to all registered generators. These do not. The minimum unit size should be at the NERC Reportable Disturbance level for the control area. Variations in any other sized unit need not even be reported. This isn't about treating all generators fairly, it is about what is affecting BPS reliability.
No
We don't agree that four points are needed for baseload units. We strongly agree with the Commission's statement that "such a requirement for all generators may not be necessary." First, we

believe 2.2, of Attachment 1 to the standard, should exempt all base load units (not just nuclear units) from verification of reactive capability at minimum real power output. There are other units that the industry should be able to exempt based on their normal operating modes. Examples are peaker CTs and units that have restrictions (environmental, run of the river, etc.) preventing operation at minimum load. This concern is addressed in Paragraph 1321 of the FERC Order which states: "...other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary." Also, we not believe that verification for leading capability should not be required where operational practices preclude operation in a leading mode. Finally, for units where verification of multiple points are needed to satisfy the FERC directive, we agree that 2 points are sufficient to verify the lagging capability and 2 points are sufficient to verify the leading capability across the generator MW operating range. However, trying to represent that with a straight line approximation between the two points could eliminate a large portion of the available capability curve around rated pf when rated MW for the unit falls within the stator rating segment of the capability curve, especially when it approaches the stator limit (which can occur for some units).
Yes
No
Only if they are required for particular units.
No
They are owned and registered differently.
No
No
Engineering analysis should also be available
No
The point is that the rating should be changed to the value tested. If a unit can't reach it, it's not a rating.
Yes
The temperature adjustment probably varies by region. There is no basis in the ROP for members on one region to vote on requirements for another region. There are nationwide standards or regional standards. The SDT can't have it both ways.
Yes
For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
Yes
Yes
Yes
The standard as drafted contains regional standards (ERCOT vs WECC). The ROP doesn't permit members of one region to vote on regional requirements for other regions. Regional standards will be required to implement regional differences.
Yes
Regional differences violate the ROP.

Yes
This standard imposes significant costs on generators and requires them to, in many cases unless they are also a transmission company, to hire consultants to conduct the verification. There is no evidence that unverified model data for units smaller than the level of the NERC Reportable Disturbance for the control area will have any impact on BPS reliability.
No
Not sync condensers
No
Not registered
No
There is no evidence that this needs to be done to any unit less than the NERC Reportable Disturbance level for the control area.
No
For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
No
One year history should be sufficient. It's about the verification, not keeping paper or electronic records forever.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
No
No
Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of the BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Yes
No
30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Yes
Yes
Yes
Yes

No
If by expected, it means maximum/minimum, then no. In many operating conditions, one does not get within 20% of the maximum/minimum. Need to be clear about what expected means.
No
No
Yes
The proposed VSL levels are spaced 10 days apart. For a test which is done once in a 5 year, it is unnecessarily restrictive. The minimum spacing between the VSLs should be 90 days. Reporting results 90 days late or even a 180 days late does not cause any concern for a planning horizon study. This data is only needed for such studies and such cases are typically updated annually. The real power verification tests are unnecessary and do not add any value. The peaking unit with less than 5% capacity factor should be expempt.
Yes
Yes
No
No
Verification on units less than 50 MVA is an unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Yes
No
30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Yes
Yes
No
No
Verification on unites less than 50 MVA is unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Yes
No
30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Yes
Yes
Yes

Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
No
In the ERCOT Region, Oncor believes that the appropriate entity to receive this information is the Planning Authority.
Yes
Oncor believes that this information should be submitted to the Planning Authority in the ERCOT Region and that they (the Planning Authority) should coordinate with the Generator Owner in the development of any correction factor and the appropriate temperature value that should be used.
Yes
No
Unit reactive capability is limited by many factors and cannot be estimated using a straight line approach, a region of reactive capability over various power levels using actual operating limits is more realistic.
Yes
Yes
No
Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard
No
Oncor does not believe that there is a reliability based need for the verification of synchronous condensers under this standard therefore we believe this criterion is not applicable to this standard.
Yes
No
Any operational varation from expected should be explained by the Generator Owner and a solution to provide full capability be presented.
Yes
Oncor also recommends that consideration be given to a regional variance in that the information required of the Generator Owner as specified in R1 should be provided to the Planning Authority in the ERCOT region and not the Transmission Planner. This would align with current protocols, operating guide and planning guide as it relates to resource testing.
Yes
In the ERCOT Region, resource testing and most all communications regarding unit performance is facilitated by the Independent System Operator who is the Planning Authority. This is consistent with current, ERCOT protocols, operating guide and planning guide.
No
No
Yes
No

Oncor does not believe that the inclusion of dynamic reactive devices such as SVC's should be included in MOD-027-1
Yes
Oncor is in general agreement of the standards however, Oncor believes that the Transmission Planner in the ERCOT Region is not the appropriate receiving entity of test verification data from the Generator Owner. Oncor believes that a regional variance should be given strong consideration such that the Planning Authority would be the receiving entity of all testing data from the Generator Owner. This would align with current ERCOT protocols, operating guide and planning guide at it relates to resource testing and verification.
Yes
Sections 3.2.1 and 3.2.2 of the ERCOT Operating Guides direct resource entities to communicate operating capabilities directly to the ERCOT ISO. The ERCOT ISO is registered as the Planning Authority. Section 3.3 of the ERCOT Operating Guides direct resource entities to communicate changes to operating capabilities to the ERCOT ISO. Various resource test requirements as listed in Section 8 of the ERCOT Operating Guides indicate data submissions to the ERCOT ISO.
No
Yes
Yes
No
Oncor does not believe that there is a reliability need for including dynamic or static reactive resources (e.g. static VAr compensators) that are not located at generating sites in this standard.
Yes
Yes
Yes
Yes
Yes
No
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
IMPA supports combining MOD-024-1 and MOD-025-1 into a single standard MOD-025-2.
No
According to VAR-002-1, the Transmission Operator is responsible for providing the voltage schedule to the Generator Operator. This voltage schedule is to ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained. It seems like the TOP should know what the generating units are capable of producing when it comes to reactive power. IMPA recommends adding the TOP entity to the requirement 1.3.
No
The owner or operator of the generating unit should do the temperature correction to a specified temperature as directed. The owner will possess the curves and be better acquainted with the unit's limitation and temperature correction.

Yes
IMPA supports the SDT’s decision to have the standard be applicable to the compliance registry.
No
IMPA believes that four point testing is excessive and that only two points need to be verified. Those two points would be over-excitged (lagging) and under-excited (leading) reactive capability at the rated Real Power capability only. The two points verified at the expected minimum Real Power output is excessive. Reactive power support happens when load is high and generating units are running at maximum Real Output capability.
Yes
Yes
Yes
Yes
Yes
Yes
IMPA believes that the first sentence of requirement 2.1. does not read correctly in the sense that it is requiring the verification of Real Power Capability at maximum over-excited and under-excited reactive capability at rated gross Real Power Capability. This sentence would make sense if Real was removed at the beginning of the sentence and read “Perform verification of Reactive Power capability of all generating…”. Requirement 2.2 covers real power testing requirements. Since Real power needs to be removed from 2.1 then requirement 2.3 needs to have the requirement 2.2 added to it to cover the Real power testing time.
Yes
IMPA supports the application of the standard to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 50MVA and greater.
Yes
Yes
No
IMPA is answering this question in conjunction with question 9. IMPA believes that the study should happen initially and only if a change is made or equipment is modified. If using this approach, the previous evidence and the new evidence should be retained.

Yes
IMPA does not understand the need to perform the coordination type of study every five years. It should be performed initially and only if something changes that would require a new coordination study. IMPA could see the need to verify the settings on the voltage regulating equipment, etc. just as you would with relay testing but why go through a complete study every 5 years. IMPA recommends performing the coordination study initially as per the timetable listed in the effective dates (section 5) and then again prior to the implementation of systems, equipment, setting changes, etc. IMPA recommends not using the words “verify the existence” in requirement 1.2. This wording is very vague in the sense that it may require just a review of the document to ensure no changes or does it mean that another coordination study needs to be performed. IMPA recommends using the wording “shall review the coordination identified in Requirement R1 at least once every five years or perform the coordination identified in Requirement R1 within 90 calendar days… ” if this is the intent of the SDT.
Individual
Oscar Herrera
Los Angeles Department of Water and Power
LADWP does not have a position on this question at this time.
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LADWP does not have a position on this question at this time.
Yes
MOD-025 Attachment 1 Sec. 2.1 During normal operations, it is typical to have many wind and solar units not working due to equipment malfunctions such as faults. How will failures that prevent the testing of 90% of equipment integrate with the standard? MOD-025 Attachment 1 Sec. 4 Will As-Built Project Drawings suffice for the requirement? The development of new one-line diagrams for a simplified version could have a significant impact because it will require the support of drafting resources which might not be available potentially delaying the submittals of Models and Data Reports. The requirement of directional arrows for Reactive Power Flows can be superimposed on the As-Built drawings. MOD-025 Attachment 1, Sec. 5 From a user’s perspective, it would be useful to get some language from the ERO that quantifies and qualifies what type of control system conditions would trigger the need for a new model and data verification, and also to have access to a comprehensive sample of a model and data verification test plan. This would allow the user to better manage its compliance implementation phase.
LADWP does not have a position on this question at this time.
LADWP does not have a position on this question at this time.
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Individual
John Yale
Chelan County PUD
Yes
Yes
No
Should only be required if it impacts the data or test performed. For most generation it would not.
No
For multi-unit hydro and wind plants this can become a large effort. A "type" test where one of an identical family of units is verified is more practical and should provide sufficient data.
Yes
It is adequate, but variation from testing at the extremes should be permitted due to conditions - in some applications it is difficult to go to full buck or boost without absorbine/providing the reactive power from another unit without impacting the voltage schedule. Should testing cause the voltage schedule to be violated (or worse an unacceptable voltage condition), what should govern? It is unreasonable to expect that every plant over 75MVA can go to these conditions and hold them for an hour.
No
What is the basis for an hour? It should be tested to demonstrate stability at that point and not trip. After that why stay at an extreme condition? If you are concerned about MVA verification that can be done at any value, certainly design output and power factor is a better point.
Yes
Yes
For hydro, 20% of min and max reactive may be difficult to achieve. Salient pole machines have much greater lattitude than thermal, but system and bus conditions dictate if it is possible. Allowance should be made for realities in these cases. Again, what will dictate - voltage schedule or testing requirements?
Voltage schedule requirements may conflict.
No
Yes
Yes
No
No

No
Yes
Yes
Yes
If there is a reliabiity need for synch-condensors and generators, why not SVCs for similar minimum capacity? don't they similarly impact system reliability?
Yes
Yes
Yes
Yes
No
No