Background:

The Phase III & IV drafting team thanks all who submitted comments on the first posting of the Phase III & IV Standards. After careful review and consideration of the comments received, the drafting team has modified the standards and is posting the standards in two separate sets –Set One was posted from September 1 – October 15 and Set Two is being posted from October 15 through November 30, 2005.

This 'Consideration of Comments' document only includes the comments on the standards that are in 'Set Two' and they are listed in the Index on the following pages. Note that the drafting team organized the sequence of standards in this document so they are listed in alphanumeric order by topic. The consideration of comments on the standards that are in 'Set One' of Phase III & IV Standards are posted at:

http://www.nerc.com/~filez/standards/Phase-III-IV.html

The drafting team encourages you to read the 'Background Information' posted with draft 2 of the revised standards. The Background Information provides an overview of the most significant changes made to the Phase III & IV Standards in response to stakeholder comments. In this document, stakeholder comments have been organized so that it is easier to see the summary of changes being requested of each standard. The comments can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Phase-III-IV.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Cauley at 609-452-8060 or at gerry.cauley@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments and Responses:

Commenter	Reliability Need	Acceptable Translation	Comments

EOP-005-1 System Restoration Plans (Revision of EOP-005-0)

Commenter	Reliability Need	Acceptable Translation	Comments
Entergy			(From Q 4 – Other comments) The two Measures included in this Standard are concerned only with Rquirement 11. A third measure should be added to measure R1 - R10. The wording in the Data Retention part of the Compliance Section seems appropriate: "The Transmission Operator must have its plan to reestablish its electric system available for review by the Regional Reliability Organization at all times."

Response: Measure #1 addresses R8 and R9 and M2 addresses R10. The other requirements were part of the existing V0 standard and adding measures for these requirements is outside the scope of this SAR.

Commenter	Reliability Need	Acceptable Translation	Comments
SPP Transmission Working Group	Yes	No	Title should be changed to System Restoration because standard covers more than restoration plan, includes policy portions in R11. Applicable to TPs and PAs. R1-remove APPLICABLE, each plan should address all of the elements of EOP5. If they apply simply states it.

Response: The title was established for Version 0 which contained requirements to have a system restoration plan as well as requirements to restore the system; the drafting team believes that modifying the title as suggested is outside the scope of the SARs.

The comment provided does not provide the drafting team with sufficient information concerning applicability to Transmission Planners and Planning Authorities to determine whether they should be included in the standard.

R1 is part of the existing V0 standard and modifying the requirement is outside the scope of this SAR.

Commenter	Reliability Need	Acceptable Translation	Comments
NERC Interconnection Dynamics Working Group	Yes	No	The title should be: System Restoration, because the standard covers more than just the plan, it includes the policy portions in R11. — R1-R10 Restoration Plan – needs better organization, change the order to: Plan elements, Plan Coordination, Plan validation, Plan Review & Update, and Plan Training. — Add applicability to Transmission Planners and Planning Authorities.

Response: The title was established for Version 0 which contained requirements to have a system restoration plan as well as requirements to restore the system; the drafting team believes that modifying the title as suggested is outside the scope of the SARs.

Commenter	Reliability Need	Acceptable Translation	Comments

The comment provided does not provide the drafting team with sufficient information concerning applicability to Transmission Planners and Planning Authorities to determine whether they should be included in the standard.

The order of presentation is subjective. This is a modification of a Version 0 Standard, and changing the Version 0 requirements isn't within the scope of the SAR unless the requirements are related to the Phase III & IV measures.

Commenter	Reliability Need	Acceptable Translation	Comments
Greg Mason – Dynergy Generation	Yes	No	1.Need to include Generation Owners in Section 4(Applicability). 2.Generation Owners should be included in Section B,R4. 3.In Section B,R9 need to eliminate "its" wording as TO's may not own blackstart generating units. 4.In Section B,R10 need to change "or" in second line to "and" and change "units to be cranked" in fourth line to "units to be started."

Response:

1 & 2. While the Transmission Operator and Balancing Authority do need to coordinate their actions with other entities, including Generator Operators, it is the Transmission Operators and Balancing Authorities that are responsible for the restoration-related tasks addressed in this standard.

3. The word, 'its' was replaced with, 'the' as suggested.

4. The standard was revised to clarify that diagrams are one type of documentation. Your suggestion to change, 'units to be cranked' to 'units to be started' was adopted and is reflected in the revised standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	R1 -- remove applicable, each plan should address all of the elements of EOP5. If they don't apply simply state it. R12 -- By deleting R12 the requirement to have the unit available is lost. I know that it is not the TOs responsibility to make generation available, however, the TO does need to know that black start units are available if needed. Maybe this requirement should be in another standard

Response: R1 is part of the existing V0 standard and modifying the requirement is outside the scope of this SAR. .

The draft standard did not contain an R12.

Commenter	Reliability Need	Acceptable Translation	Comments
FRCC	Yes and	No	References to EOP-005 Attachment in R1 need to be deleted and the applicable elements need to be added into the requirements, including a requirement that the TOP must provide its

Commenter	Reliability Need	Acceptable Translation	Comments
	No		plan to the RRO upon request. R2 should qualify the level of "changes in the power system network" that would require the Transmission Operator to review and update its restoration plan to ensure that R2 only requires the review and updates when network changes occur that could impact the restoration plans. R7 requires that the verification of the restoration procedures by actual testing or by simulation. Actual testing should be removed from the standard because "actual" testing of the restoration procedure is impractical since it would adversely impact customers. R8 should be the responsibility of the RRO and not of the individual Transmission Operators. References to EOP-005 Attachment in the Compliance section needs to be deleted.

Response: R1, R2 and R7 are part of the existing V0 standard and modifying these requirements is outside the scope of this SAR.

The drafting team modified R8 to clarify that the TOP is verifying that the units can perform their intended functions as required in the Regional restoration plan.

See first response to these comments.

Commenter	Reliability Need	Acceptable Translation	Comments
Mohan Kondragunta – Southern California Edison	Yes	No	To improve the standard translation, SCE recommends the following changes: For the definitions, rename the term “Cranking Path” to “System Restoration Critical Path” For R8, the requirement for a T.O. to verify blackstart sufficiency to meet RRO requirements is unreasonable. The T.O. should verify sufficient blackstart for their restoration plans or their ISO, not the RCC. As worded, Requirement R9 implies that the Transmission Operator owns the blackstart units in its system restoration plan which may not be the case. Therefore, change Requirement R9 to read: “… demonstrate, through simulation or testing, that the blackstart generating unit(s) in its restoration plan can perform…”

Response: Most commenters agreed with the definition and it wasn’t changed.

The drafting team modified R8 to clarify that the TOP is verifying that the units can perform their intended functions as required in the Regional restoration plan.

The standard was modified R9 (now R10) to clarify that the TOPs do not own the units.

Commenter	Reliability Need	Acceptable Translation	Comments
Individual Members of CCMC	Yes	No	Measure contains additional requirements of supplying a document within 30 days – this is a requirement, move to R9 Levels of non-compliance do not cover R8. The level of Non-compliance use the words "element" and "requirement" but it is not clear what is intended, e.g. (1) does R8 contain 3 elements or is it an element and where is this defined and (2) is R8 concerned addressed if one or two of the three components included under R8 are addressed.

Response: The current format for NERC standards includes specifying the response time for providing evidence in the Measures of the standard.

The levels of non-compliance were modified to address R8 (see level three).

The word, ‘element’ is used in the portion of non-compliance that was approved as part of Version 0 and modifying this is outside the scope of the SAR.

Commenter	Reliability Need	Acceptable Translation	Comments
Consolidated Edison	Yes	No	IV.A.M2 has not been fully translated into R10 and measure M2. The Measures should include other restoration plan measures, not only those related to blackstart. In R9, it is important that serious consideration should be given to blackstart testing more frequently than "at least every five years." The Drafting Team should clarify the term Startup Function in R9 to distinguish between simple blackstart of a unit(s) and the ability to perform restoration service. We suggest reformatting the restoration plan requirements as separate bulleted subrequirements and then reformatting the Blackstart unit testing section into subRequirements for clarity.

Response: The drafting team added a separate requirement (R10) to perform simulation or testing at least once every five years to demonstrate the blackstart units can perform their intended function.

Adding measures for the existing V0 standard’s requirements is outside the scope of this SAR.

The planning measure being translated, (IVA.M.2) states, “Such simulation or testing shall be performed at least every five years. “ The ‘testing’ in this standard is aimed at testing whether the blackstart unit can perform as intended, and is not the same as testing to verify that the unit can start. EOP-009 R7 requires testing blackstart units to verify that they can startup.

Commenter	Reliability Need	Acceptable Translation	Comments

The drafting team modified R9 so that the term, 'startup function' is not used.

Changing the sequence of requirements approved as part of V0 is outside the scope of what is necessary to incorporate the requirements for IVAM2 and IVAM3. .

Commenter	Reliability Need	Acceptable Translation	Comments
P.D. Henderson Khaqan Khan	Yes	No	IV.A.M2 and IV.A.M3 have not been fully translated into EOP-005 requirement R9, R10 and measure M2. Moreover, the Measures should also include other restoration plan measures, not only those related to blackstart. In R9, consideration should be given on testing of blackstart more frequently rather than "at least every five years". Simulation of unit testing should not be allowed and there should be a requirement to test any blackstart related facility on an annual basis. Drafting Team to expand the term Startup Function in R9 to require both a blackstart of a unit(s) and the ability to perform restoration service.

Response: The drafting team added a separate requirement (R10) to perform simulation or testing at least once every five years to demonstrate the blackstart units can perform their intended function.

Adding measures for the existing V0 standard's requirements is outside the scope of this SAR.

The planning measure being translated, (IVA.M.2) states, "Such simulation or testing shall be performed at least every five years. " The 'testing' in this standard is aimed at testing whether the blackstart unit can perform as intended, and is not the same as testing to verify that the unit can start. EOP-009 R7 requires testing blackstart units to verify that they can startup.

There was some confusion about what was meant by 'startup function' and this term is not used in the revised standard.

Commenter	Reliability Need	Acceptable Translation	Comments
ISO/RTO Council Standards Review Committee Ed Riley – California ISO	Yes Yes	No No	IV.A.M2 and IV.A.M3 are not fully translated into R9 and R10 and measure M2. The Measures should include other restoration plan measures, not only those related to blackstart. Drafting Team to clarify the term Startup Function in R9 to distinguish between simple blackstart of a unit(s) and the ability to perform restoration service.

Response: The drafting team added a separate requirement (R10) to perform simulation or testing at least once every five years to demonstrate the blackstart units can perform their intended function.

Adding measures for the existing V0 standard's requirements is outside the scope of this SAR.

Commenter	Reliability Need	Acceptable Translation	Comments

There was some confusion about what was meant by ‘startup function’ and this term is not used in the revised standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Vinod Kotecha	Yes	No	IV.A.M2 has not been fully translated into R10 and measure M2.
Michael C. Calimano – NYISO	Yes	No	The Measures should include other restoration plan measures, not only those related to blackstart.
Kathleen Goodman – ISO-NE	Yes	No	In R9, it is important that serious consideration should be given to blackstart testing more frequently than "at least every five years". Simulation of unit testing should not be allowed and there should only be a requirement to test the Units at least once every five years and any blackstart related facility on an annual basis.
Alan Adamson – NYSRC	Yes	No	Drafting Team to clarify the term Startup Function in R9 to distinguish between simple blackstart of a unit(s) and the ability to perform restoration service.
NPCC CP9 RSWG	Yes	No	Suggestion to reformat the restoration plan requirements as separate bulleted subrequirements and then reformat the Blackstart unit testing section into subrequirements for clarity.

Response: The drafting team added a separate requirement (R10) to perform simulation or testing at least once every five years to demonstrate the blackstart units can perform their intended function.

Adding measures for the existing V0 standard’s requirements is outside the scope of this SAR.

The planning measure being translated, (IVA.M.2) states, “Such simulation or testing shall be performed at least every five years. “ The ‘testing’ in this standard is aimed at testing whether the blackstart unit can perform as intended, and is not the same as testing to verify that the unit can start. EOP-009 R7 requires testing blackstart units to verify that they can startup.

There was some confusion about what was meant by ‘startup function’ and this term is not used in the revised standard.

Making modifications to the Version 0 sections of the standard is outside the scope of the SAR for this standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Kansas City Power and Light	Yes	No	The new R9 and R10 seem to be a rewording of the existing R7 and R8. One of these sets of requirements needs to be eliminated.

Response: The drafting team made significant changes to the standard in response to your comment regarding R9 and R10.

Commenter	Reliability Need	Acceptable Translation	Comments
Pacific Gas and Electric			COMMENT: R3 states "the Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection". R11.4 states "The affected Transmission Operator shall give high priority to restoration of off-site power to nuclear

Commenter	Reliability Need	Acceptable Translation	Comments
			stations". These two statements could result in confusion in terms of priority (i.e. the Interconnection or offsite power to a nuclear station). Restoring offsite power to a nuclear station may not contribute to restoring the bulk power system and its interconnections, therefore, may be judged a lower priority by the Transmission Operator. The NRC expects the restoration of offsite power to a nuclear power plant to be the highest priority. COMMENT: R8 is too general regarding the capability of blackstart units. Blackstart unit capability should also be sufficient to meet nuclear offsite power requirements. COMMENT: R9 should require that documentation of simulation / testing acceptance be transmitted to the nuclear power plants. COMMENT: R10 Same comment as R9, documentation applicable to nuclear offsite power cranking paths should be provided to the nuclear power plants. COMMENT: R11.5.4 should specifically exclude nuclear offsite power from any load shedding.

Response: Making changes to Version 0 requirements (R3, R11.5.4) is outside the scope of the SAR.

The drafting team is translating the Phase III & IV measures and they do not address the additional requirements identified in your comments relative to R8, R9, and R10. Note that there is another SAR under development that addresses the same issues you've identified.

Commenter	Reliability Need	Acceptable Translation	Comments
Mark Kuras – MAAC	Yes	No	Several of the requirements (R2, R3) should be sub-requirements under the requirement to have a restoration plan (R1). Seems like too many requirements are included in this standard, break up the standard into more than one standard. Measurements do not align to the requirements. Many more measurements are needed and then need to be reflected in the levels of non-compliance. Level 2 mentions and Attachment. What is this? Suggest that a separate blackstart standard be created instead of trying to insert the Blackstart requirements in an incomplete operating standard that needs a lot of work.

Response: R1, R2 and R3 are Version 0 requirements and modifying these is outside the scope of the SAR.

Adding measures for the existing V0 standard's requirements is outside the scope of this SAR.

The drafting team will ask stakeholders if they feel that this should be subdivided with the requirements related to the two planning measures in a separate standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Peter Burke – American Transmission Co.	Yes	No	V1 of this standard should be enhanced to include Measures that address all the Requirements R1--R11 comprising it. While the translation of IV.A.M2-M3 resulting in R8, R9, R10 and M1-M2 is acceptable, not fixing the pre-existing deficiencies (i.e. absence of any Measures) in the V0 standard makes the resulting EOP-005-1 an incomplete V1 revision.
Response: Adding measures for the existing V0 standard's requirements is outside the scope of this SAR.			
Xcel Energy – Northern States Power	Yes	No	Measure M1 - The intent of this measure is to validate the elements of the restoration plan, either by simulation or physical testing. Demonstration of the black-start units ability to perform the functions of the restoration plan is too restrictive, and conflicts with EOP - 009. Recommend this measure be written as follows: " The Transmission Operator shall , within 30 calendar days of a request, provide its Regional Reliability Organization with documentation of simulations or tests that demonstrate the resources (including cranking paths) identified in the Transmission Operator's restoration plan are sufficient to support its restoration plan." Measure M2 - Providing documentation can be interpreted as sending doucmentation off-site, which can be a conflict as this documentation is considered as Critical Utility Infrastructure information. This measure should be rewritten as "provide documentation or diagrams showing number, size and location of blackstart generating units identified in the Transmission Operator's restoration plan and the associated cranking paths for view at the Transmission Operator's location.
Response: M1 - The drafting team made changes to the draft standard to reflect your comment. M2 – Your suggestion was adopted and is reflected in the revised standard.			
Joseph D Willson – PJM	Yes	No	Level 4 2.4.2 goes beyond the elements of Requirement 9 The levels of non-compliance are difficult (and therefore subjective) to measure. Measure contains additional requirements of supplying a document within 30 days
Response: The drafting team revised the levels of non-compliance so they align with the new requirements. The drafting team discovered the posted standard inadvertently omitted attachment 1 that described the plan elements. The drafting team incorporated the contents of attachment 1 directly into the standard and added more specificity to the associated requirements that linked to			

Commenter	Reliability Need	Acceptable Translation	Comments

specific levels of non-compliance.

The current format for NERC standards includes specifying the response time for providing evidence in the Measures of the standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	Generator testing frequency may be as much as 5 years under the proposed standard per Requirement 9. I believe that this is far too long given the critical function of system restoration. The need for more frequent testing is underlined by the fact that some Black Start generators in PJM, for example, do fail to start under normal operations. Also, there have been anecdotal comments in PJM regarding a lack of maintenance for some Black Start units. Thus, frequent testing ought to be done to ensure that Black Start resources are actually likely to be available. Almost every other standard in Phase III-IV has a reset period of 1 year and I urge that the retest period for "black start" generation be set to 1 year. Further, under 1.3 of Compliance, the proposed addition sets the record retention period to 3 years. This appears to conflict with the 5 year frequency of generator testing. Recommend, at a minimum, that all time frames in EOP-005-1 be aligned.

Response: The 'testing' in this standard is aimed at testing whether the blackstart unit can perform as intended, and is not the same as testing to verify that the unit can start. EOP-009 R7 requires testing blackstart units to verify that they can startup.

The performance reset period is one year.

The data retention section of the standard does require the Compliance Monitor to retain audit data for three years, but does not require the responsible entity to retain its data for any specific period of time.

Commenter	Reliability Need	Acceptable Translation	Comments
Gerald Rheault – Manitoba Hydro	Yes	Yes	In items R5, R6 and R7, the required action frequency should be specified as a measurable amount. In R1 the attachment (Attachment 1-EOP-005-0) contained in EOP-005-0 should be included instead of just being referenced. R5: should clarify objective of the test of telecommunications facilities. R11.5.2: What is the intent of this requirement? Measures: Why wouldn't documentation of the restoration plan be a measurement? R1 requires a plan, but does not explicitly say you have to document it. The first sentence on part 5 "The

Commenter	Reliability Need	Acceptable Translation	Comments
			Transmission Operator …at all times" requires a plan to be provided to the RRO. Why do we need 11 requirements if you are only going to measure compliance to two requirements?

Response: R1, R5, R6, R7 and R11 are original V0 requirements and modifying these is outside the scope of the subject SAR.

The Attachment was erroneously omitted from the first posting – the attachment will appear with the standard in the second posting.

The requirements of NERC standards are intended to enhance the reliability of the bulk electric system; documentation, although required, does not directly enhance the reliability, but is required for demonstrating compliance.

Many of the requirements in this standard are from Version 0 and adding measures for existing requirements is outside the scope of the SAR.

Commenter	Reliability Need	Acceptable Translation	Comments
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Recommend that Level 3 non-compliance be made not applicable and the current Level-3 description be moved to Level-4 as 2.4.3.
Southern Company Generation	Yes	Yes	
Southern Company Transmission	Yes	Yes	
SERC EC Planning Standards Subcommittee (PSS)	Yes	Yes	
Entergy	Yes	Yes	

Response: The drafting made changes to support the intent of your suggestion..

Commenter	Reliability Need	Acceptable Translation	Comments
Midwest Reliability Organization	Yes	Yes	R5. The term "periodically" should be changed to some measurable frequency. R6 and R7 should have a required frequency added to the requirement.

Commenter	Reliability Need	Acceptable Translation	Comments
			R1. Will need to remove reference to old version 0 document and create reference to new version 1 attachment 1.

Response: R1, R5, R6, and R7 are original V0 approved requirements and modifying these is outside the scope of the subject SAR.

Commenter	Reliability Need	Acceptable Translation	Comments
Transmission Agency of Northern California	Yes	Yes	There appears to be a typo in Requirement R10. We suggest removing the word [associated] in the second line. In Requirement R9, Measure M1, and Level of Non-compliance 2.4.2, we suggest changing the word [simulation(s)] to [calculations]. In this context, simulations could lead some people to believe that power flow studies need to be performed. However, in many cases, a simple hand or spreadsheet calculation may be all that is needed to show that the plan will work as designed.

Response: The word “associated” has been removed. The drafting team believes “simulation” includes calculations and therefore should not be modified.

Commenter	Reliability Need	Acceptable Translation	Comments
Doug Hohbough – First Energy Corp.	Yes	Yes	This analysis is best performed on a Dispatcher Training Simulator or similar computer model with dynamic capabilities containing the model of the system being studied. This may not be available to all members of the industry. Those organizations without this capability would be relegated to the testing method which may or may not be a viable option depending upon system configurations.

Response: Thank you for your comment.

Commenter	Reliability Need	Acceptable Translation	Comments
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	Yes	R4 We recommend adding blackstart generator owner to the list of entities with whom the transmission operator will coordinated the blackstart restoration plan. R9 We recommend changing "startup functions" to "system restoration functions" to avoid confusion with the requirement to periodically demonstrate the ability of blackstart generators to start without grid support.
Deborah M. Linke – US Bureau of	Yes	Yes	

Commenter	Reliability Need	Acceptable Translation	Comments
Reclamation			

Response: R4 is an existing Version 0 requirement, and making modifications to this requirement is outside the scope of the SAR.

There was some confusion about what was meant by 'startup function' and this term is not used in the revised standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Karl A. Bryan - US Army Corps of Engineers	Yes	Yes	I think there also needs to be a requirement for the transmission operator to prove that the system restoration plan works as well as to prove that the blackstart generators are actually capable of energizing a line and picking up a load. My experience has been that blackstarting a generator is the easy step, it is picking up the transformer and transmission line charging currents that cause a generator the most problems.

Response: The 'testing' in this standard is aimed at testing whether the blackstart unit can perform as intended, and is not the same as testing to verify that the unit can start. EOP-009 R7 requires testing blackstart units to verify that they can startup.

The standard was revised to add a separate requirement (R10) to perform simulation or testing at least once every five years to demonstrate the blackstart units can perform their intended function.

The drafting team also believes that TOP may not be able to test its plan by energizing a line and picking up a load due to system topology and reliability concerns therefore it maintains simulation as an acceptable alternative to physical plan validation per the standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Resource Issues Subcommittee	Yes	Yes	1) In R11, Transmission Operators and Balancing Authorities should not take any action until coordination is made with their Reliability Coordinator(s). Suggest changing R11 to "Following a disturbance in which one or more area of the Bulk Electric System becomes isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to implement the following steps:" 2) In Compliance Section 2.4.2, suggest deleting "regional".

Response: R11 was approved, as written, in Version 0. Making the suggested change would change the intent of R11 and is outside the scope of the SAR.

The drafting team disagrees with deleting the word regional because the TOP's plan needs to be compliant with the regional plan.

Commenter	Reliability Need	Acceptable Translation	Comments
Tennessee Valley Authority	Yes	Yes	In "Levels of Non-Compliance" section 2.4.2, delete the word "regional."

Response: The drafting team disagrees with deleting the word regional because the TOP's plan needs to be compliant with the regional plan.

EOP-005-1 System Restoration Plans (Revision of EOP-005-0)

Commenter	Reliability Need	Acceptable Translation	Comments
Transmission Issues Subcommittee	Yes	Yes	TIS has no additional comments.
PPL Corporation	Yes	Yes	
WECC Reliability Subcommittee	Yes	Yes	
Howard Rulf - WE Energies	Yes	Yes	
John Horakh – MACC	Yes	Yes	
Raj Rana – AEP	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	Yes	

Comments on Field Testing and Effective Date:

There were no comments suggesting field testing of this standard or suggesting alternate effective dates.

MOD-016-1 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management (Revision of MOD-016-0)

Commenter	Reliability Need	Acceptable Translation	Comments
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	I believe that the language in the Purpose section is insufficiently precise. I suggest that the first sentence be modified to read: "To ensure that accurate, actual demand data is available and to support assessments and validation of past events and databases."
Response: Adopted revision to clarify purpose statement.			
Mohan Kondragunta – Southern California Edison WECC Reliability Subcommittee	Yes Yes	No No	SCE agrees with the data reporting requirements, but has a concern with the LSE as the responsible entity. Within the WECC region, control areas are currently the reporting entity. Prior to legislation, perhaps a backstop should be created wherein the balancing authority (BA) is responsible for providing data for LSEs within their area if the LSE is not providing the data.
Response: Functional model designates LSE as responsible for developing and reporting load forecast data. LSEs may have procedures or agreements that delegate the task to others, but ultimately the LSE has the information and the responsibility.			
Kansas City Power and Light	Yes	No	It appears the drafting team has chosen to rewrite this proposed standard and add new requirements. The Planning Authority should not be deleted from this standard.
Response: The Planning Authority was returned as suggested.			
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	I oppose deleting the Planning Authority from this standard. There are cases where the RRO is not the Planning Authority and vice versa. This standard is to require the data for modeling purposes. The RRO is not necessarily the one building the models. Instead of a translation of the IID.M2 it looks like the drafting team decided to completely rewrite MOD-16. The translation goes way beyond the requirement to ensure no data is omitted or counted multiple times. The measures should be swapped. M2 measures R1 and M1 measures R2. Renumber M1

Commenter	Reliability Need	Acceptable Translation	Comments
			to M2 and M2 to M1 and reorder them. I disagree with the comment that it is not necessary to state requirements in other standards. This is done for reference to ensure that the requirements of one standard that apply to portions of another standard are accurate and not over looked by the party responsible for compliance. Therefore I disagree with the deletion in R2 D 1.1.1 compliance monitoring should include the RRO for monitoring the PA.
Response: The Planning Authority was returned as suggested. The additional requirements that were in the first draft have been removed from the revised standard. The cross reference was returned to the standard as suggested. There was only one measure in the first draft of the standard. The Compliance Monitor for the PA was returned as suggested.			
FRCC	Yes	No	Agree that the amount of controllable DSM load should be reported (R4) but there should not be a requirement to report the location of customer load. The amount of controllable load is needed to determine the level of adequacy of Resources. Collecting the location of controllable load would be used only in situations where deliverability of resources is a concern. If there is a requirement to report the location of controllable customer load, it should only be a requirement on an aggregated basis over a geographic region when there are deliverability concerns. Requiring that entities report the location of all controllable customer load is burdensome and not worthwhile. R6 should be changed to "Each Regional Reliability Organization shall use" (delete "A requirement that" at the beginning of R6), since the RRO should not develop a procedure requiring itself to something. M1 should be in Section C. (Measures) and the requirements at the end of the measure should be R2 to R5, not R1 to R6. Compliance section should be Section D and the requirements in Level 2 and 4 of non-compliance should both be R2 - R5 (not R1 only).
Response: R4 and R6 have been removed from the revised standard. Formatting and numbering errors were corrected.			

Commenter	Reliability Need	Acceptable Translation	Comments
Individual Members of CCMC Joseph D Willson – PJM	Yes No	No No	R2-R7 should be sub-bullets of R1. Can’t tell if compliance is to be measured against R1 or R1 through R7. It appears that the “clean version” file is different from the mapping file. Standard is missing section C heading for Measures. It appears that the “clean version” file is different from the mapping file. Measure 1 adds a requirement not contained in the Requirements for this standard. This should be in requirements..
Response: Formatting and numbering errors were corrected. The standard was extensively revised to remove the requirements that went beyond the Phase III & IV Measures (R2-R7) Measures were revised to align with the revised requirements.			
Consolidated Edison Vinod Kotecha IESO – Ontario Alan Adamson – NYSRC Kathleen Goodman – ISO-NE NPCC CP9 RSWG	Yes Yes Yes Yes Yes Yes	No No No No No No	R1.5 the use of the actual and forecast data as directly provided by the LSE must be analyzed to ensure it is properly aggregated to reflect coincident peak demands for system modeling and reliability analyses. It is suggested that the word "incorporate" be used instead of "use" in that Requirement. Also there is a formatting error in this Standard. M1 as it appears in the Requirements Section needs revision. R1 should be the Section and R2-R8 should be "sub" requirements due to the language at the end of R1.
Response: The standard was extensively revised to remove the requirements that went beyond the Phase III & IV Measures (R2-R7 or R1.2 through R1.6) Formatting and numbering errors were corrected.			

Commenter	Reliability Need	Acceptable Translation	Comments
Michael C. Calimano – NYISO	Yes	No	Please note the formatting correction in NPCC's comment
Response: Formatting and numbering errors were corrected.			
SPP Transmission Working Group	Yes	No	Under B (requirement) item M1 be removed it is not a requirement
Response: Formatting and numbering errors were corrected.			
Peter Burke – American Transmission Co.	Yes	No	The formatting of and the number of Requirements and Measures listed in the clean Draft1 standard document is inconsistent with the translation mapping document. The version in translation mapping document is more acceptable since it is a better translation. Agree with removing Planning Authority as applicable entity and making this standard applicable to RRO only. A.3 Suggest adding interruptible load. R1.3 Suggest adding available trip speed of DSM load and adding amounts, location, and available trip speed of interruptible load.
Response: Formatting and numbering errors were corrected. Controllable load is meant to include interruptible load. The drafting team removed all the requirements that were added with the 1st posting that were outside the scope of the Phase III & IV planning Measures, including R1.3.			
John Harris - Load Forecasting Working	Yes	Yes	Deletion of standard II.D.M3 is acceptable because its requirements have been merged with MOD-016-0.

Commenter	Reliability Need	Acceptable Translation	Comments
Group			
Response: Thank you for your comment.			
John Horakh – MACC	Yes	Yes	Ok to delete Planning Authority
Response: Deleting the Planning Authority was outside the scope of the SAR and it has been returned.			
Data Coordination Working Group	Yes	Yes	DCWG agrees with merging II.D.M2 into MOD-016 for clarity and efficiency among the data requirements standards. Additional clarity and efficiency could be gained by merging some parts of the other existing, related standards (MOD-016 through 021). For example, MOD-019, MOD-020 and MOD-021 could be merged into MOD-016 through MOD-018 - interruptible and load control do not need to be separated from demand and energy. Arguably, MOD-020 could remain separate as it requires the reporting of interruptible and load control to operating entities while the balance of the MOD-016 through MOD-021 are planning entity related. DCWG also believes that changing the applicability of MOD-016 to RROs instead of RROs and PAs is appropriate, clarifies responsibilities and reduces the possibility of "double jeopardy" among these standards (an entity being found non-compliant on multiple standards because of a non-compliance on a single element of a standard).
Response: Thank you for your support and comments. Additional changes to the organization of the standards would be beyond the scope of the current project. Deleting the Planning Authority was outside the scope of the SAR and it has been returned.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	Heading "Measures" is missing. MOD-017-0 should be modified to better compliment the revised MOD-016-1. Purpose: What is meant by "databases can be formed"? Data Retention: Who is the auditor - first time mentioned in the standard.

Commenter	Reliability Need	Acceptable Translation	Comments
Response: Formatting and numbering errors were corrected. MOD-017 is beyond the scope of the current project. Purpose has been revised to a more active statement. Auditor replaced with compliance monitor.			
Midwest Reliability Organization	Yes	Yes	The heading for the "Measures" Section is missing. It is necessary for the requirements in MOD-016-1 to be complimentary to the requirements in MOD-017-0 regarding applicability for Load Serving Entities. MOD-016-1 and MOD-017-0 need to coordinate to address this issue.
Response: Formatting and numbering errors were corrected. Changing MOD-017 is outside the scope of the current project.			
Ed Riley – California ISO ISO/RTO Council Standards Review Committee	Yes Yes	Yes Yes	Also there is a formatting error in this Standard. M1 as it appears in the Requirements Section needs revision. R1 should be the Section and R2-R8 should be "sub" requirements due to the language at the end of R1 In some ISO/RTO market regions there are third party aggregators of DSM products (i.e. curtailment service providers) that are not LSEs. Thus the information requirements of R4, R5, and R7 would be met by non-LSE's.
Response: Formatting and numbering errors were corrected. Functional model designates LSE as responsible for developing and reporting load forecast data. R 2-R7 were outside the scope of the SAR and have been removed from the revised standard.			
Entergy SERC EC Planning Standards Subcommittee (PSS)	Yes Yes	Yes Yes	Recommend that R5 be revised to read “A requirement that each Load-Serving Entity update its actual and forecast customer demand values at least once each year according to a schedule.”

Commenter	Reliability Need	Acceptable Translation	Comments
Response: R 2-R7 were outside the scope of the SAR and have been removed from the revised standard.			
Mark Kuras – MAAC	Yes	Yes	Remove items under Data Retention. First item is redundant with the standard. Second item is part of the auditing procedures of each region and don't need to be part of the standard. Remove text under Additional Compliance Information because it is up to the region how it will do compliance and should not be part of the standard.
Response: This is standard format being used across the standards.			
Raj Rana – AEP	Yes	Yes	Format Fix required: Need "Measures" Heading. Requirements numbering in the draft standard does not agree with comparison document. How do the last 2 requirements relate to the levels of non-compliance?
Response: Formatting and numbering errors were corrected. The first draft of this standard included several requirements that were outside the scope of the associated SAR, and these have been removed. The measures and levels of non-compliance were modified to align with the revised requirements.			
Tennessee Valley Authority	Yes	Yes	
Xcel Energy – Northern States Power	Yes	Yes	
Joseph F. Buch – Madison Gas and Electric	Yes	Yes	
Howard Rulf - WE Energies	Yes	Yes	
Karl A. Bryan - US Army	Yes	Yes	

Commenter	Reliability Need	Acceptable Translation	Comments
Corps of Engineers			
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	
Greg Mason – Dynergy Generation	Yes	Yes	

Comments on Field Test and Effective Date

There were no comments suggesting field testing this standard or suggesting alternate effective dates.

Entergy			(From Q 4 – Other comments) The last sentence of R.4 "open circuit test … terminal voltage." appears to be the same as Requirement R.5 and should be deleted.
Response: R4 was redundant and was deleted. The open circuit test in R5 was moved to R1.4.5 to more clearly show it is part of the verification results to be reported.			
Greg Mason – Dynergy Generation			(From Q 4 – Other comments) For Generation Owners, all of MOD-026-1 seems largely redundant to MOD-012-0.Suggest deleting Generation Owners from MOD-012-0.
Response: MOD-012 addresses reporting of data and what types of data need to be reported. MOD-026 focuses specifically on 'verification' of excitation system and voltage control model data that has already been provided.			
IESO			(From Q 4 – Other comments) 1. We suggest adding a requirement for Generator Owners to provide automatic to manual AVR tracking validation. 2. We suggest adding more tests to ensure the stabilizers are working properly (e.g. Step Tests) 3. We suggest replacing the term 'data' with 'models and data' in the sentence: "The Generator Owner shall, within 30 calendar days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner(s) 'data' associated… " 4. R2 - We suggest replacing the term 'verify' with 'validate' in the sentence: "The Generator Owner shall 'verify' the data used in… 5. R3 - If any of the information outlined in this requirement is unavailable, we suggest obligating the Generator Owner to perform tests that are necessary to verify the model.
Response: 1. AVR tracking is addressed in the VAR standards (VAR-001 for the TOP and VAR-002 for the generator). 2. Details of testing requirements are to be established in the RRO's procedure. The purpose of this standard is not to ensure that equipment is working properly, it is to ensure that the data used in models is accurate.			

3. The standard was modified to state more specifically what data and models need to be verified. 4. The drafting team believes that 'verify' is a better term than 'validate', and is consistent with language used in other standards. 5. The RRO's procedures must identify acceptable methods of model and data verification.			
PPL Corporation			(From Q 4 – Other comments) The Regional Reliability Organization needs to determine the frequency and overall criteria required for any generation testing in support of these new standards. The needs basis shall only evaluate units that have a significant affect on the safe and reliable operation of the transmission system. Any test that is required on generator equipment needs to be subject to a risk analysis where the value of the test is evaluated against the risk that such test would impact the generation equipment and transmission system. Only units or stations that have a significant affect on the system should be tested. Nuclear units should be exempted from on-line testing unless the Nuclear Generator Owner can demonstrate through the 10CFR50.59 screening process that such testing is not an Unreviewed Safety Question (USQ). PPL believes that real-time operational data could be used in lieu of on-line testing in some instances to validate the range of reactive capabilities.
Response: The drafting team agrees. The RRO was assigned responsibility for developing these procedures so that these procedures can reflect regional needs. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. The commenter is encouraged to offer assistance in developing the regional procedures.			
SPP Transmission Working Group			(From Q 4 – Other comments) MOD-023 thru 027 should include planning authorities.
Response: The Planning Authority was added as a recipient of the RRO's procedures and the Generator Owner's data in MOD-024 through MOD-027.			
Pacific Gas and Electric			Our facility is on a 20-22 month fuel cycle and should not be required to do testing requiring taking the unit offline mid-cycle, for example, to do open circuit response tests.
Response: Frequency of verifications and any exemptions are to be addressed in the RRO procedure. The commenter is encouraged to offer assistance in developing the regional procedures.			

Wing Joe- BC Hydro	No Answer	No	Model should align with the equipment, not the reverse. It is unreasonable to expect the Generator Owner to verify the data the transmission planner use in their model of the system. The only obligation that the Generator Owner should bear is to provide the necessary equipment info to the transmission planner, who then includes that equipment in his/her system studies.
Response: The purpose statement has been revised to make this clarification.			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	I interpret requirement for an annual open circuit response test. Recommend a longer time frame unless operational anomalies are encountered.
Response: The standard does not require an annual open circuit response test. The annual reset period for monitoring compliance should not be interpreted as a testing periodicity requirement. Frequency of verifications is to be addressed in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedure.			
Joseph F. Buch – Madison Gas and Electric	Yes	No	The standard requires verification of the data but does not spell out what the data is or how it is to be verified. It also requires open circuit test response chart recordings but does not spell out who's responsible for developing the test. In addition it requires excitation system model data and verification without indicating the type of model. It is recommended that this standard undergo field testing to better define the requirements. At the same time the need to provide data on small units (<50 MW) or those with manual operation should be evaluated. Units on manual operation, or small units likely provide little if any benefit and the cost of testing needs to be justified.
Response: Verification methods are to be determined in the RRO's procedure. The standard was revised to clarify what data and models must be verified and reported. The commenter is encouraged to offer assistance in developing the regional procedures. The drafting team is recommending that this standard be field tested before it is finalized. The RRO's procedure must identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.			

Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	No	MOD-026-1 as written places the burden on the Generator Owner to verify data used in dynamic models for excitation systems while not having any expertise in system studies, model derivation and use. This standard, and specifically requirements R2, R3 and R5 would result in a Generator being required to furnish, within thirty days, excitation data on 20, 30.. or more units with accompanying field testing that may be required, all without missing any elements. I question how many deregulated utilities can meet that standard. While I do agree that a program is needed to ease into a joint database of excitation parameters between System Planners and Generator Owners this standard goes beyond full cooperation.
Response: The Generator Owner can delegate the task of verifying data if the Generator Owner doesn't have the expertise to verify data. The standard has been revised so it should be easier to identify what models and data must be verified. The RRO procedure will address the requirements and timing of required data. The '30 days' is intended to identify the time period the GO has to provide the data once the data has been requested. The GO is expected to have already conducted the verifications, and to have the data available. The drafting team is proposing that this standard be field tested before it is finalized. Once finalized, the drafting team is recommending that the standard's effective date be phased in so that the GO will have several years to achieve full compliance. The commenter is encouraged to offer assistance in developing the regional procedures.			
Mark Kuras – MAAC	Yes	No	The main issue remains whether or not to require testing of generating unit excitation systems. The term …verify… is too vague and seems to invite either confusion or continuation of the status quo. The listing under R3 is a hodge-podge of qualitative and numerical responses. The list neither requires that the excitation system model conform to IEEE Standard 421.5, nor that simulation code to implement non-conforming models be provided and documented. If no IEEE standard or PSSE or PSLF/PSDS standard library model adequately represents excitation system response, the generator owner should be required to have a user-defined model written and validated and provide documentation to the user community. In many cases generator owners may not have expertise to conduct any independent review of vendor data, particularly to determine whether any device settings have changed sufficiently to affect vendor estimates of model parameters but this does not relieve them of the responsibility to provide an adequate simulation model. A periodic review or retesting interval should be specified for parameters affected by field

			adjustable settings. Change Data Retention text to require that the Generator Owner shall retain commissioning and test reports and data as long as either (1) the equipment is in service or (2) events in which its response was significant remain under investigation. Delete text under Additional Compliance Information because it is up to the region as to how compliance will be measured. This text adds nothing to the standard.
Response: An open circuit test is required in the revised standard. The drafting team believes and is supported by industry comment, that alternative methods for verification of data can also be valid. The applicable methods are to be identified in the RRO's procedure . The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue.. The generator owner retains responsibility for accurate generator data, even if the generator owner does not have the expertise in house. The Generator Owner may delegate this task. Frequency of verifications is to be addressed in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. The data retention requirement has been revised to be consistent with other standards. The compliance information identifies how compliance with NERC standards will be determined. If the compliance information indicates that compliance will be measured through annual self-certification, then that is how the Compliance Monitor must measure compliance with this standard. It is not completely up to the Region to determine how to measure compliance with NERC Standards.			
Multi-Regional Modeling Working Group	Yes	No	The main issue remains whether or not to require testing of generating unit excitation systems. The term …verify… is too vague and seems to invite either confusion or continuation of the status quo. Some units need to be tested and others don't. An example of a determining factor for testing is whether a unit is stability constrained or its participation in poorly damped power swings. The listing under R3 is a hodge-podge of qualitative and numerical responses. The list neither requires that the excitation system model conform to IEEE Standard 421.5, nor that simulation code to implement non-conforming models be provided and documented. If no IEEE standard or PSSE or PSLF/PSDS standard library model adequately represents excitation system response, the generator owner should be required to have a user-defined model written and validated and provide documentation to the user community. The generator owner must be required to demonstrate that the model and parameters

			provided under R3 will simulate a response corresponding to the test charts of R4 or R5. In many cases generator owners may not have expertise to conduct any independent review of vendor data, particularly to determine whether any device settings have changed sufficiently to affect vendor estimates of model parameters but this does not relieve them of the responsibility to provide an adequate simulation model. A periodic review or retesting interval should be specified for parameters affected by field adjustable settings. Change Data Retention text to require that the Generator Owner shall retain commissioning and test reports and data as long as either (1) the equipment is in service or (2) events in which its response was significant remain under investigation. Delete text under Additional Compliance Information because it is up to the region as to how compliance will be measured. This text adds nothing to the standard.
Response: An open circuit test is required in the revised standard. The drafting team believes and is supported by industry comment, that alternative methods for verification of data can also be valid. The applicable methods are to be identified in the RRO's procedure. The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue.. The generator owner retains responsibility for accurate generator data, even if the generator owner does not have the expertise in house. Frequency of verifications is to be addressed in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. The data retention requirement has been revised to be consistent with other standards. The compliance information identifies how compliance with NERC standards will be determined. If the compliance information indicates that compliance will be measured through annual self-certification, then that is how the Compliance Monitor must measure compliance with this standard. It is not completely up to the Region to determine how to measure compliance with NERC Standards.			
Tennessee Valley Authority	Yes	No	If a model does not conform to an IEREE standard or PSSE or PSLF/PSDS standard library model, the generator owner should be required to have a user-defined model written and validated. Test reports should always be provided to the transmission planner along with the model so independent checking so generator verification is possible. There should be a MW cutoff – exemption that is allowed if approved by the Transmission Provider.
Response: The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of			

quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue. The standard as drafted requires the data to be provided to the transmission planner. Exemptions are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures.			
Vinod Kotecha	Yes	Yes and No	Although in concept collecting this information has value, the actual testing required to validate the parameters could be a detriment to reliability. NERC needs to consult with those who perform dynamic analysis and seek their input and weigh it appropriately.
Response: The RRO was assigned responsibility for developing these procedures so that these procedures can reflect regional needs. The commenter is encouraged to offer assistance in developing the regional procedures.			
Constellation Generation Group	Yes	No	Requirements need to be more specific. What method of verfication is acceptable? There is not standard test out there.
Response: The applicable methods are to be identified in the RRO's procedure. The open circuit test is a very common, standardized test and is the only specific test that is required in this standard. The commenter is encouraged to offer assistance in developing the regional procedures.			
SPP Transmission Working Group	Yes	No	Title should read VERIFICATION OF GENERATOR EXCITATION SYSTEM AND VOLTAGE CONTROL MODELS. Purpose should be changed to the first sentence of the old standard. R1 & R3 should include the Planning Authority. Refer to Funtional Model, Planing Authority, 1c.
Response: The title has been revised. The purpose has been clarified. Planning authority has been added as a recipient of the RRO's procedures and as a recipient of the GO's data.			
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	R3 should include the Planning Authority. Refer to Functional Model, Planning Authority, 1C.
Response: Planning authority has been added as a recipient of the RRO's procedures and as a recipient of the GO's data.			

Kansas City Power and Light	Yes	No	It appears that these requirements are addressed in standards MOD-010 through MOD-013. R1 and R3 should include the Planning Authority
Response: MOD-010 to 013 address reporting of data and what types of data need to be reported. MOD-026 focuses more specifically on verification of excitation systems and voltage control models. Planning authority has been added as a recipient of the RRO's procedures and as a recipient of the GO's data			
Greg Mason – Dynergy Generation	Yes	No	1. NERC should not eliminate specifying a minimum verification frequency(every 5 years in the current standard).NERC should provide this guidance to the Regions. Regions can always be more stringent when regional needs require more frequent verification. Therefore, suggest adding "every five years" verification requirement in Sections B,R1, B,R2, B,R3 and C,M1. 2. Analogous to comment #1 above, Section B,R4 should include the one year requirement that in Section M6 of the current standard. 3. Section B,R5 appears to be a new requirement relative to the current standard and should be deleted. Also, the same wording in Section B,R4 seems to cover the intent of the current standard.
Response: Frequency of verifications is to be addressed in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. R5 was derived from the original II.B.M6 which included the following: Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.)			
FRCC	Yes	No	The requirements for the proposed standard should be limited to R1 only. Delete R2 - R5. MOD-23 gives the RRO the responsibility to identify the required testing and the verification requirements. While it is important to have accurate excitation system models, the reliability improvement gained does not always justify the manpower requirements to test and verify the interconnected synchronous generators. If R2 - R-5 remain requirements for this standard, we do not support this as a standard.
Response: The drafting team subdivided MOD-023 and distributed the RRO's requirement to develop procedures directly into MOD-024 through MOD-027. Revised MOD-026 contains the RRO's requirement to develop a procedure for data verification, along with the Generator Owner's requirement to verify and report that data. The revised MOD-027 reflects deletion of most of R5. R2-R5 from the 1st draft of this standard were extensively revised to clarify what data and models need to be verified and reported as part of the RRO's procedure.			

The new R1 identifies minimum requirements that need to be addressed in the regional procedure. The standard allows the region significant latitude in establishing what verification methods are acceptable within the region to verify this data. The drafting team is recommending that this standard be field tested before it is finalized.			
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson Deborah M. Linke – US Bureau of Reclamation	Yes Yes	No No	R3.3 requires model and data verification of over and under excitation limiters. IEEE is still working to develop a model for limiters after which the dynamic simulation software vendors will incorporate the models into their programs. We recommend striking verification of limiter models until models approved by the RRO are available. We also recommend as a practical matter that a phase-in period be provided by the RRO. This will allow entities with a large number of machines to distribute the validation and re-validation process over a period of time (3-5 years).
Response: The language has been revised to require the RRO's procedure to require the GO to verify and report its 'Verified static set points for under and over excitation limiters'. The requirement to verify over and under excitation limiter models was deleted as suggested. The drafting team is recommending that this standard be field tested before it is finalized. As envisioned, the standard's effective date would be phased in over several years.			
Kenneth Dresner – FirstEnergy Solutions	Yes	No	Section R2 - 1. The word 'verify' needs additional clarification, such as, ". . . Owner shall verify by test, configuration control reviews or other means the data used in dynamic models . . ." These two standards should be kept separate to help facilitate tracking compliance at the physical level and help focus on the areas of non-compliance MOD-023-1 calls out a separate requirement for each of the proposed merged standards The ability to identify the need for a change in excitation system a year in advance is not always practical and therefore the need to submit information a year in advance should be dropped or modified accordingly

Response: The applicable verification methods are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. The standard was revised so that the RRO's requirements to develop data and model verification procedures was removed from MOD-023 and added to MOD-024 through MOD-027. The revised MOD-026 includes the RRO's requirements to develop the procedures as well as the GO's requirements to follow those procedures. Revised MOD-026 attempts to clearly list what information needs to be verified and reported. There is no requirement to submit information a year in advance.			
Trilok C. Garg – Mirant Mid Atlantic	Yes	No	Paragraph BR1 - Not clear, what information can be provided for ,'limiters, compensators". suggest to remove the wordings - limiters, compensators.
Response: 'Limiters' has been clarified by adding 'static'. The requirement was reworded to clarify what was intended. The revised standard includes the following under the list of data to be provided: R1.4.3 Static set points for under and over excitation limiters. R1.4.4 Line drop compensator settings.			
NERC Interconnection Dynamics Working Group	Yes	No	Title should be changed to: Verification of Generator Excitation Systems and Voltage Control Models — Purpose should be modified to: To verify generator excitation system models and parameters (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) used to assess Bulk Electric System reliability. — R1 – The Generator Owner shall…and applicable Transmission Planner(s) modeling data associated with…Organization requirements. The data shall be compatible with the standard excitation system models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. — R2:…shall verify the data used in models … In the absence of generator model validation standards; this will be difficult to enforce. — R1 – This data submittal aspect is already addressed in MOD-012-0 and MOD-013-0 (both have typo/format errors). Such duplicate inconsistent requirements need to be avoided in Industry STANDARDS. — R3, R4 and R5: …as required by the RRO procedures… imply that these need to be addressed by the RRO procedures. But MOD-023-1 does not require RRO procedures to

			address those things. — Add R6: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days.
Response: The title and purpose have been revised for clarification. The standard has been extensively modified, and now includes both the RRO's requirement to develop procedures for verification of models and data related to generator excitation system functions. The revised standard requires the GO to 'follow its RRO's procedures'. The RRO's procedure will identify what methods are acceptable for conducting the validation or verification. Note that this standard will be field tested before it is finalized, and any shortcomings in the RRO's requirements should become apparent when the standard is field tested. If there are typos in MOD-012 and MOD-013, please follow the steps for reporting errata with the Version 0 Standards which are posted on the Web Page with Version 0 Standards. MOD-012 and MOD-013 require data be provided for models, and this standard requires the model data to be verified. MOD-026 was revised to clarify what data is to be verified and reported under this standard. The drafting team subdivided MOD-023 and distributed the RRO's requirement to develop procedures directly into MOD-024 through MOD-027. Revised MOD-026 contains the RRO's requirement to develop a procedure for data verification, along with the Generator Owner's requirement to verify and report that data, eliminating the inconsistencies noted between R3, R4, and R5 with MOD-023. The standard was revised to include the following requirement which addresses your concern: R1.3 Periodicity and schedule of model and data verification and reporting, including schedules associated with planned units, existing units, field changes to existing units, new units, and refurbished units.			
Southern Company Generation	Yes	No	SDT should incorporate the levels of non-compliance for this standard as recommended for MOD-024. R1 & R3 - The 30 day reporting requirement is too demanding, especially if a large number of units are involved. R5 should allow for alternatives to the open-circuit step response test. This new standard will require extensive operation effort, engineering analysis, and field testing to accomplish. Furthermore, it is impractical for a Utility with many large generating units to accomplish full compliance in a short time period. While we agree fundamentally there is a reliability need for this standard, the reliability importance and impact of all

			generators on the system is not the same. A phased approach that prioritizes the implementation for existing generators would provide reliability benefits and help reduce the strain on industry resources. We recommend this approach be reflected under the Compliance section, allowing an initial seven calendar year phase-in period, then one calendar year. The accomplishment of this should be coordinated with Standards MOD-025 and PRC-019.
Response: The drafting team is recommending that this standard be field tested before it is finalized. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance. The RRO's procedure must identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures. 30 days refers to the time administratively to respond to a request, not to perform data verifications. It is anticipated that the data will be available already, per the reporting schedule outlined in the RRO's procedure. The RRO's procedure may define alternative verification methods. The commenter is encouraged to offer assistance in developing the regional procedures. The implementation of this standard does not rely on any other standard. However, MOD-026, PRC-019 and MOD-027 are all expected to have phased-in effective dates that require an additional 20% of the units to become compliant each year. (Effective dates can't be established for MOD-026 and MOD-027 until after field testing has been completed.)			
Southern Company – Transmission	Yes	No	Requirements R3.1, R3.2, R3.3, R3.4, R3.5, R3.6, R3.7 belong in MOD-023. These are details that should be specified in the Regional requirements. R3 should say -The Generator Owner shall, within 30 calendar days of a request, provide to the Regional Reliability Organization and applicable Transmission Planner(s) the results of excitation system model and data verification, including the information as required by the Regional procedures.- Same comments as on MOD-025, including levels of non compliance and the 2 - 3 year time period before being held to compliance requirements. R1 & R3 - The 30 day reporting requirement is too demanding, especially if a large number of units are involved. It is impractical for a Utility with many large generating units to accomplish in a short time period. R2 - We recommend that you add a note that says changes in AVR, PSS and other controls

<table>
<tr><td></td><td></td><td></td><td>should be communicated, in real time, to TOP.

In R3 – The model supplied has to be usable. There is a practice by certain manufacturers of supplying an unknown model which does not fit into any known stability program. The generator owner should be required to supply data that is applicable for known models that have been approved and are commonly available, e.g. IEEE models. If the model is a new, standard models must be developed and established for industry-wide use. Further, proprietary dynamic models for existing generators shall be converted to standard models or new models must be developed and established for industry-wide use</td></tr>
<tr><td colspan="4">Response: The drafting team subdivided MOD-023 and distributed the RRO’s requirement to develop procedures directly into MOD-024 through MOD-027. Revised MOD-026 contains the RRO’s requirement to develop a procedure for data verification, along with the Generator Owner’s requirement to verify and report that data.

MOD-026, is expected to have phased-in effective dates that require an additional 20% of the units to become compliant each year. (Effective dates can’t be established for MOD-026 and MOD-027 until after field testing has been completed.)

The requirement for the GO to provide data was modified so that the GO has to ‘follow its RRO’s procedure for verifying and reporting . . . The timing requirement is now left up to the RRO to specify in its procedures.

The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.

30 days refers to the time administratively to respond to a request, not to perform data verifications. (Note that the ’30 days’ was not included in the revised standard – instead the modified standard requires the GO to ‘follow the RRO’s procedures’ – and the RRO’s procedures must include a schedule and periodicity for verifying and reporting.

It is anticipated that the data will be available already, per the reporting schedule outlined in the RRO’s procedure.

Reporting of real-time status of AVR and PSS is addressed in separate standards.

The suggested requirements to improve consistency of the quantitative models, including use of IEEE models, can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus to define standardized models within a NERC standard at this time.</td></tr>
<tr><td>SPP Generation Working Group</td><td>Yes</td><td>No</td><td>R2: To obtain this data the generator will need to inject/absorb the maximum amount of VAR it can produce at various MW level. Hence you have similar operating problems and coordination problems as discussed in MOD-025.

R5: This test requires the unit to be off line. Some units are scheduled to be on line over 18 months prior to an overhaul. Taking the unit off line, strictly for testing, could be very costly due to the replacement energy cost might be natural gas base as opposed to a coal base.</td></tr>
</table>

			Hence the time between tests must to be longer then one year. Compliance: Similar testing concerns to as discussed in MOD-025. This testing will require sophisticated monitoring equipment. A concern exists that if the entire country adopts this standard there will not be enough equipment nor manpower to get it done in such a short period. Taking the unit off line, strictly for testing, could be very costly due to the replacement cost of energy might be natural gas as opposed to coal that the unit to be tested is burning. Hence the time between tests must to be longer then one year. If a company has similar units, we would propose that one unit be tested and those characteristics would be applied to other similar units in the company's fleet, similar to WECC's testing procedure. GWG believes a minimum of a five year testing cycle is more appropriate o If a company has similar units, we would propose that one unit be tested and those characteristics would be applied to other similar units in the company's fleet, similar to WECC's testing procedure. o OG&E believes a minimum of a five year testing cycle is more appropriate.
Response: The drafting team does not believe the draft standard requires a max leading/lagging injection of reactive. The applicable verification methods are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. Exemptions and timing of testing are to be addressed in the regional procedure. The drafting team is recommending that this standard be field tested before it is finalized. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.			
Joseph D Willson – PJM	No	No	Level 1 is difficult to measure and may be going beyond the stated requirements. Level 3 should only reference R4 R1 Remove the "within 30 days of a request" here and in every requirement that it shows up. Data, documentation, etc should be available whenever requested. M1 seems to go beyond the stated requirement.
Response: The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance. References to requirement numbers have been corrected.			

30 days was intended to be the administrative time to gather and submit the data following a request. It is expected the verification data would be developed and available per the RRO procedure. The standard was modified to remove the '30 days' of a request. The standard's measure was modified so the GO is reporting as required in the RRO's procedures.			
Individual Members of CCMC	Yes	No	Level 1 is difficult to measure and may be going beyond the stated requirements. Compliance is a function of finding the appropriate Regional documents and basically doing a Regional compliance check – more a Regional compliance program. Level 3 needs to be rewritten to include R4 which appears appropriate for inclusion. R1 Remove the "within 30 days of a request" here and in every requirement that it shows up. Data, documentation, etc should be available whenever requested. This makes short notice audits difficult and does not allow for checking that things are done in real time, such as checking that documents are readily accessible to operators. M1 seems to go beyond the stated requirement.
Response: The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance. 30 days was intended to be the administrative time to gather and submit the data following a request. It is expected the verification data would be developed and available per the RRO procedure. The standard was modified to remove the '30 days' of a request – and to simply require the GO to 'follow the RRO's procedures'. The associated procedures must include the reporting requirements, including the schedule and periodicity for reporting the information. M1 was modified to better align with the associated requirements.			
Kathleen Goodman – ISO-NE	Yes	Yes	Although in concept that collecting this information has value, the actual testing required to validate the parameters could be a detriment to reliability. The development of this standard need more technical development.
Response: The tests are usually conducted offline and should not be a threat to system reliability. The commenter is encouraged to offer assistance in developing the regional procedures.			
Barry Green – Ontario Power Generation	Yes		There is some inconsistency in this package of standards affecting generators, between applicability to generator owner in some cases and generator operator in others. For this standard, MOD-026-1, the applicability must lie with the generator operator. In many cases, the owner, by virtue of contractual obligations, would not have the ability to carry out the obligations imposed by this standard. In other cases, ownership could be shared and it would

			not be appropriate for these obligations to be shared. Therefore, the applicability of this standard more correctly belongs with the generation operator. Alternatively, if NERC chooses to be less prescriptive, it could, for the purposes of the standard, place an obligation on the owner or operator, with an obligation on the region to clarify in each case, the appropriate entity to meet the requirements.
Response: The functional model assigns capability verification to the generator owner. The comment could be an issue when there are joint owners, but in these cases there are agreements to address delegation of this task among the owners.			
WECC Reliability Subcommittee Mohan Kondragunta – Southern California Edison	Yes Yes	Yes Yes	WECC RS agrees with the removal of the five-year testing requirement and that it should be established by the RRO.
Response: Thank you for the comment.			
John Horakh – MACC	Yes	Yes	Good conversion from prescribed testing to verification. However the Generator Owner may require significant time beyond November 1, 2005 for the initial verification. An effective date of five years beyond Board approval is more realistic.
Response: Thank you for the comment. The drafting team is recommending that this standard be field tested before being finalized. As envisioned, the standard's effective date would be phased in over several years.			
Samuel W. Leach – TXU Power	Yes	Yes	The overall excitation system respponse values can be tested and verified. However it can be very difficult and sometimes imporactical to verify individual regulator and PSS subsystem components. Manufacturer desgin constants should be accepted where verification testing is impractical.
Response: The drafting team believes the open circuit step response test will verify the overall excitation system response, including the voltage regulator response. The standard was revised to address the individual pieces of the excitation system in enough detail to verify the accuracy of associated models.			

NPCC CP9 RSWG	Yes	Yes	NPCC participating members believe that although in concept that collection this information has value, the actual testing required to validate the parameters could be a detriment to reliability. (needs work however doesn't apply to the RRO)
Response: The tests are usually conducted offline and should not be a threat to system reliability. The commenter is encouraged to offer assistance in developing the regional procedures.			
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Using the term verify is vague and subject to different interpretations by various entities. Although there is opposition to field testing generating units, it needs to be acknowledged that field testing is the best way to obtain accurate models and parameters for generator equipment. Because of the large volume of tests to perform, and the high cost to perform them, field testing should be phased-in over a 5 to 8 year time period. It is not possible to test all required units within a one year time frame. The Levels of Non-Compliance as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO the levels of non-compliance should be rewritten as proposed in the comments provided by the SERC Planning Standards Subcommittee (PSS).
Response: The applicable methods are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. The drafting team is recommending that this standard be field tested before being finalized. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance. The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.			
PPL Corporation	Yes	Yes	Generating units also provide a vital dynamic response to system voltage transients and an important voltage regulation function. PPL supports the objective of the proposed standard to verify that these functions are modeled correctly. PPL believes that real-time operational data can provide much of the data required by the Regional Reliability Organizations to verify the modeling of a generator's dynamic response to transients and whether or not the generator is following its voltage or reactive schedule. While PPL believes there is some value in performing certain off-line tests such as a voltage step test, we do not see a need to repeat these tests unless modifications have been made to a generator's excitation systems. In addition, units of size less than 70 MWs should be

			exempt. PPL believes that a NERC standard should require all Generator Owners to have their Automatic Voltage Regulators (AVRs) in service and to immediately report any AVR outages to the system operator
Response: The applicable methods are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. Exemptions for verification are to be addressed in the RRO's procedure. The requirement to have AVR in service and report outages is addressed in VAR-001 and VAR-002.			
Midwest Reliability Organization	Yes	Yes	Assume the standard allows for the RRO to approve of exemption for smaller units?
Response: Yes.			
Transmission Issues Subcommittee	Yes	Yes	There is the potential for wide variance in verification procedures among RROs. The RRO requirements should require physical testing of the generator excitation system. This standard should include a requirement for NERC review of the RRO's verification procedures. The standard should establish a maximum five year period for verification of capabilities, unless there is a change in equipment or a setting change, at which time the generator excitation system should be retested.
Response: The drafting team believes the open circuit step test is the minimum required to provide a benchmark for the excitation system's overall response - the results can be used to determine accuracy of model data. The RRO procedure can define alternative verification methods for obtaining other data. The applicable methods and periodicity are to be identified in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedures. The drafting team is recommending that this standard be field tested – shortcomings in the requirements for the RRO procedures should become apparent during the analysis of the field testing, and could lead to revisions in the standard. NERC is the Compliance Monitor for the RRO, and will review the procedures.			
Peter Burke –	Yes	Yes	R2 should this read "… shall verify the data submitted for use in dynamic models.."?

American Transmission Co.			
Response: The standard was extensively modified to clarify what models and data need to be verified.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	Include a requirement to coordinate unit protection settings with the excitation limiters and frequency of testing required. R3.7: What is meant by "method of verification"?
Response: Protection coordination is required in PRC-019. Methods of verification will be defined by the RRO's procedure.			
IESO – Ontario	Yes	Yes	R4 - Needs to clarify that when is the data required - This should be consistent with requirements R1.2 as stated in MOD-028-1
Response: The RRO procedure will define when the data is required.			
Jerry Nicely – TVA Nuclear Generation	Yes	Yes	R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods.
Response: The drafting team believes the open circuit step test is the minimum required to provide a benchmark for the excitation system's overall response - the results can be used to determine accuracy of model data. The RRO procedure can define alternative verification methods for obtaining other data.			
Xcel Energy – Northern States Power	Yes	Yes	R4 - The specific contained in R5 (exciter field voltage and current data for brushless units) needs to be added to R4 as the same rules apply.
Response: The standard was extensively revised and the identified requirements have been merged.			
D. Bryan Guy – Progress Energy, Inc.	Yes	Yes	PEC supports the language used that allows fo alternate methods of verifing data for modeling other than testing.

			R4- Delete last sentence which is covered in R5. Revise R5 to replace "…chart recordings showing…" with "…data that includes..."
Response: Requirements have been merged and requirement for charts removed.			
Resource Issues Subcommittee	Yes	Yes	1. R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods. 2. RIS believes that consideration should be given in this standard to collecting the appropriate data to verify that units will perform as simulated. All of the information requested in R3 may not be necessary, and should not be required unless specified by the Region.
Response: The drafting team believes the open circuit step test is the minimum required to provide a benchmark for the excitation system's overall response - the results can be used to determine accuracy of model data. The RRO procedure can define alternative verification methods for obtaining other data. The standard was extensively revised to clarify what data and models need to be verified and what information needs to be reported. The items listed in MOD-026 R1.4.1 through R1.4.7 are considered 'minimum' requirements.			
SERC EC Generation Subcommittee (GS)	Yes	Yes	R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods.
Response: The drafting team believes the open circuit step test is the minimum required to provide a benchmark for the excitation system's overall response - the results can be used to determine accuracy of model data. The RRO procedure can define alternative verification methods for obtaining other data.			
AEP			Reword the title as follows: Verification of Generator Excitation System and Voltage Control Models. Reword R1 as follows: The Generator Owner shall - - - and applicable Transmission Planner(s) modeling data associated with - - - Organization requirements. The data shall be compatible with the standard excitation system models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. Delete the last sentence in R4.

			Add R6 as follows: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days. D1.2 Compliance Monitoring Period and Reset Timeframe: At installation of new equipment. Beyond that, when equipment is changed out or when setting changes are made. (Once this data becomes established and there are no further equipment changes, it is unnecessary and burdensome to keep repeatedly doing compliance reviews.) D1.3 Data Retention: Generator Owner shall retain commissioning and test reports and data indefinitely or until unit is retired. D1.4 Additional Compliance Information: The Generator Owner shall demonstrate compliance through transmitting the verified data to Transmission Owner/Operator/Planner, and through self-certification or audit - - - - as determined by the Compliance Monitor.The Generator Owner shall demonstrate compliance by handing over the requested data.

Response: The title and purpose have been revised for clarification.

The suggested requirements to improve consistency of the quantitative data reported can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue.

The last sentence in R4 said: ‘Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage.’ And was changed so that the GO must report its ‘open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units)’.

The intent of your suggestion for a new R6 was adopted and is reflected in the revised RRO requirement for procedures that include the following:

> R1.3 Periodicity and schedule of verification and reporting, including schedules associated with field changes to existing units, and refurbished units.

Compliance monitoring period defines review period for compliance, it does not define the verification period. Periodicity of verification is defined by the RRO procedure.

Data retention has been changed to current and prior verification data.

The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

<table>
<tr><td>Raj Rana – AEP</td><td>Yes</td><td>Yes</td><td>See AEP Comment</td></tr>
<tr><td colspan="4">Response: See response to AEP.</td></tr>
<tr><td>Entergy

SERC EC Planning Standards Subcommittee (PSS)</td><td>Yes

Yes</td><td>Yes

Yes</td><td>The Levels of Non-Compliance as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO, the levels of non-compliance should be rewritten as follows:
2.1. Level 1: Verified generator data were provided and were complete for less than 100% of a generator owner's units as required by the RRO procedures.
2.2. Level 2: Verified generator data were provided and were complete for less than 95% of a generator owner's units as required by the RRO procedures.
2.3. Level 3: Verified generator data were provided and were complete for less than 90% of a generator owner's units as required by the RRO procedures.
2.4. Level 4: Verified generator data were provided and were complete for less than 85% of a generator owner's units as required by the RRO procedures.</td></tr>
<tr><td colspan="4">Response:
The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.
The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.</td></tr>
<tr><td>Karl Kohlrus - City Water, Light & Power</td><td>No Answer</td><td>Yes</td><td></td></tr>
<tr><td>Howard Rulf - WE Energies</td><td>Yes</td><td>Yes</td><td></td></tr>
<tr><td>Michael C. Calimano – NYISO</td><td>Yes</td><td>Yes</td><td></td></tr>
</table>

Alan Adamson – NYSRC	Yes	Yes	
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Ed Riley – California ISO	Yes	Yes	
ISO/RTO Council Standards Review Committee	Yes	Yes	
Doug Hohbough – First Energy Corp.	Yes	Yes	
Consolidated Edison	Yes	Yes	

Members	Field Test Required?	Recommended Date?	Justification

Comments on Field Testing and Effective Date:

Summary Consideration: Based on the comments provided, the drafting team is recommending that this standard be field tested before it is finalized. An 'effective date' needs to be determined following an analysis of the field testing.

Members	Field Test Required?	Recommended Date?	Justification
Greg Mason – Dynergy Generation	Yes	7/1/07	First, per MOD-023-1 the Regions are required to determine generating unit exemption criteria to the data requirements(allow 6 months).Then for the affected units, this standard will require significant time and effort to go through data in archives to document the information(allow one year).R5 in this standard, if retained, will require unit testing as well.
Response: Several commenters suggested that this standard needs to be field tested to verify that it supports its purpose. The drafting team is recommending that this standard be field tested before it is finalized. The effective dates for the requirements in the standard need to be determined following an analysis of the results of field testing.			
Resource Issues Subcommittee	Yes		Since these generator tests will take significant time and manpower to accomplish, field testing is recommended to verify these tests produce reasonable model improvements (particularly the tests required in R5).
Jerry Nicely – TVA Nuclear Generation	Yes		
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes		
SERC EC Generation Subcommittee (GS)	Yes		
TVA	Yes		
D. Bryan Guy – Progress Energy, Inc.	Yes		
Response: Several commenters suggested that this standard needs to be field tested to verify that it supports its purpose. The drafting team is recommending that this standard be field tested before it is finalized.			

Members	Field Test Required?	Recommended Date?	Justification
Midwest Reliability Organization	Yes		Delay necessary for method standardization in MOD-023-1. Additionally, field testing and/or some external evaluation and additional costs may be necessary.
Response: Several commenters suggested that this standard needs to be field tested to verify that it supports its purpose. The drafting team is recommending that this standard be field tested before it is finalized.			
Southern Company Generation Southern Company – Transmission	Yes		Recommend field testing for the purpose of coordinating this effort between Transmission Operators, Generator Operators, and Transmission Planners and development of appropriate procedures. Various methods will be employed among different utilities and generators to do this verification. Some refinement in the processes and procedures are expected as experience is gained and should enhance the safety and reliability of the overall verification process. This supports the allowance of a reasonable period of time to achieve compliance.
Response: Several commenters suggested that this standard needs to be field tested to verify that it supports its purpose. The drafting team is recommending that this standard be field tested before it is finalized. The effective dates for the requirements in the standard need to be determined following an analysis of the results of field testing.			
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	11/01/10	The testing provisions of the standard may require data not taken during the last voltage regulator inspection and test cycle. Once the standard is approved full implementation should allow for a normal inspection cycle.
Response: The effective date for the requirements in the standard needs to be determined following an analysis of the results of field testing.			
PPL Corporation	Yes	1/1/2010	PPL feels that there is a need to analyze the test data collected over the last five years in WECC to determine if the risk and expense of these tests are off set by the value in the better model data obtained.
Response: Several commenters suggested that this standard needs to be field tested to verify that it supports its purpose. The drafting team is recommending that this standard be field tested before it is finalized.			
Xcel Energy – Northern States Power	Yes	1/2008	This is an extension of MOD-023-1. At present, there is no industry-wide accepted criteria to perform this function, and the methodology would need to come from the respective RRO process described in MOD-023 - 1. Implementation and field testing could only take place after that.

Members	Field Test Required?	Recommended Date?	Justification

Response: Several commenters suggested that this standard needs to be field tested to verify that it supports its purpose. The drafting team is recommending that this standard be field tested before it is finalized.

MOD-027-1 Verification of Generator Unit Frequency Response

IESO

(From Q 4 – Other comments)

We suggest updating requirements to make these more explicit for validation of Deadband and Droop.

Response: There is more to modeling frequency response than droop and deadband. Controls on units today are typically more complex and have overrides. System modeling requires more than droop and deadband.

PPL Corporation

(From Q 4 – Other comments)

The Regional Reliability Organization needs to determine the frequency and overall criteria required for any generation testing in support of these new standards. The needs basis shall only evaluate units that have a significant affect on the safe and reliable operation of the transmission system.

Any test that is required on generator equipment needs to be subject to a risk analysis where the value of the test is evaluated against the risk that such test would impact the generation equipment and transmission system. Only units or stations that have a significant affect on the system should be tested.

Nuclear units should be exempted from on-line testing unless the Nuclear Generator Owner can demonstrate through the 10CFR50.59 screening process that such testing is not an Unreviewed Safety Question (USQ). PPL believes that real-time operational data could be used in lieu of on-line testing in some instances to validate the range of reactive capabilities.

Response: The drafting team agrees. The RRO was assigned responsibility for developing these procedures so that these procedures can reflect regional needs.

The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.

The commenter is encouraged to offer assistance in developing the regional procedures.

SPP Transmission Working Group

(From Q 4 – Other comments)

MOD-023 thru 027 should include planning authorities.

Response: The Drafting Team subdivided the requirements in MOD-023 and placed the RRO's requirement to write procedures, and forward those procedures to the Generator Owners, into each of the standards that required the Generator Owner to verify and provide models and data (MOD-024 through MOD-027). The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator

Commenter	Reliability Need	Acceptable Translation	Comments
Owner's data in MOD-024 through MOD-027.			
Pacific Gas and Electric			Nuclear facility governors are block loaded to prevent electrical transients on the system from affecting the primary plant and testing to verify generator frequency response is probably not practical. Nuclear facilities may need an exemption from this standard.
Response: The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. The commenter is encouraged to offer assistance in developing the regional procedures.			
Tennessee Valley Authority	Yes	No	The Regional Reliability Organization is required by VAR-004 to establish voltage/frequency dip criteria, but the only standard that addresses the generator's capability to meet these criteria is this one. This standard should therefore be more specific about providing information about when the generator will trip. Generator trip settings (under/over frequency and voltage ride thru capability) should be provided to the Transmission Planner. (Essential to coordinate with UFLS).
Response: Addressed in the PRC standards on UFLS.			
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	No	MOD-027-1 goes far beyond verifying that a governor is in service or blocked. While modern electronic governors do have accurate dialed in settings for droop, deadband and other control limiters older mechanical governors do not. Their expected response may be at best a guess. Not knowing of a viable test for frequency response I do not agree with this standard as written. On a per unit basis the most accurate indicator of frequency response was evident on August 14, 2003. It is believed that the use of system event recording devices is the only way to accurately afford predictable models for reliability studies.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response.			
Samuel W. Leach – TXU Power	Yes	No	The proposed standard should be more specific as to acceptable method or methods to be used to provide verification of the speed/load governor characteristics.
Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response.			
Vinod Kotecha Kathleen Goodman –	Yes Yes	No No	Drafting Team to verify that the testing requirements that appear in the "S" language in the original Standard, has been dropped, was this intentional? There is also an analysis currently underway regarding the response of unit governors on

Commenter	Reliability Need	Acceptable Translation	Comments
ISO-NE			August 14 and also how they relate to existing system models. Results of the analysis need to be weighed in developing the appropriate standard.
NPCC CP9 RSWG	Yes	No	

Response: The intent of the 'S' statements for II.B and III.C have been translated into the new standards. The 'S' statements said:

> **II.B.S5.** Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.
>
> **III.C.S5.** Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

The proposed standards require that generator data be verified, but don't require that 'testing' be used because there are other methods of verifying data. (Note that MOD-024 and MOD-025 address verification of gross and net real and reactive power capabilities; MOD-026 addresses verification of models and data for generator excitation system functions.) The proposed standard MOD-027 requires the generator owner to identify how its unit will respond to frequency deviations – and requires the generator owner to identify the method used to make this determination. This supports the intent of the 'S' statement for III C.

Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
Consolidated Edison	Yes	No	The drafting team should verify that the testing requirements that appear in the "s" language in the original Standard has been dropped, was this intentional?
Alan Adamson – NYSRC	Yes	No	

Response: The intent of the 'S' statements for II.B and III.C have been translated into the new standards. The 'S' statements said:

> **II.B.S5.** Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.
>
> **III.C.S5.** Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

The proposed standards require that generator data be verified, but don't require that 'testing' be used because there are other methods of verifying data. (Note that MOD-024 and MOD-025 address verification of gross and net real and reactive power capabilities; MOD-026 addresses verification of models and data for generator excitation system functions.) The proposed standard MOD-027 requires the generator owner to identify how its unit will respond to frequency deviations – and requires the generator owner to identify the method used to make this

Commenter	Reliability Need	Acceptable Translation	Comments

determination. This supports the intent of the 'S' statement for III C.

Commenter	Reliability Need	Acceptable Translation	Comments
Southern Company Generation	Yes	No	SoCo Generation recommends the SDT better define the requirements of this standard. R2.2 should be deleted and may require a separate SAR to better define the requirements. The industry has not established a safe and effective means for determining the response of a generating plant to changes in system frequency. Our assessment indicates the response of generator speed and the MW output depend on the overall control system applied at the plant not just the governor. If these requirements are adopted then SoCo Generation's comments for MOD-025 regarding field testing, implementation, levels of non compliance and reportability should apply.
Southern Company – Transmission	Yes	No	

Response: Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. As envisioned, the standard's effective date would be phased in over several years. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
Kenneth Dresner – FirstEnergy Solutions	Yes	No	A standardize timeframe of 30 business days or greater to provide the data should be retained in the proposed standard The request for the nonfunctioning or blocked speed/load governor data needs a duration timeframe of possibility rolling 12 month period since the other requirements of this proposed standard have a frequency of every five years

Response: The standard was revised to require the RRO to provide its procedures within 30 calendar days of approval – and to require the GO to 'follow its RRO's procedures'. The RRO's procedures are required to address the periodicity and schedule for the GO to report its information relative to frequency response.

The drafting team is proposing a field test to determine appropriate methods for verification of generator frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
Wing Joe- BC Hydro	No	No	It may be unreasonable to expect that generator owners (or anyone else) in the electric utility industry conduct test to determine how the unit speed and real power output changes in response to frequency transients.

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
Constellation Generation Group	Yes	No	Generator can only provide design data. Response to responses to frequency excursions can not be measured, frequency characteristic is unknown and can vary. How can generator come up with data?

Response: Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
SPP Transmission Working Group	Yes	No	Title should read VERIFICATION OF GENERATOR SPEED GOVERNING SYSTEM MODELS. Change purpose to first sentence of II.B.S5. R1 & R2 should include the Planning Authority. Refer to Functional Model, Planning Authority, 1c.

Response: The proposed title and purpose do not fit the scope of the standard, which is not limited to speed governor and verification of models.

The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's data.

Commenter	Reliability Need	Acceptable Translation	Comments
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	No	R1 & R2 should include the Planning Authority. Refer to Functional Model, Planning Authority, 1C.

Response:

The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's data.

Commenter	Reliability Need	Acceptable Translation	Comments
Kansas City Power and Light	Yes	No	R1 and R2 should include the Planning Authority.

Response: The Planning Authority was added as a recipient of the RRO's procedures and as a recipient of the Generator Owner's data.

Commenter	Reliability Need	Acceptable Translation	Comments
Greg Ludwicki – Northern	Yes	No	If the method for response verification is a requirement for dynamic testing, one calendar year is over aggressive for dynamic testing. Our OEM's recommendation for such testing is not

Commenter	Reliability Need	Acceptable Translation	Comments
Indiana Public Service Co.			periodic, but only to diagnose an apparent change in governor operation or after disassembly and/or replacement of major governor parts. MOD-027B. R1Could you explain how to determine the information that you are requesting. Should the results be based on the system recovering or the system staying below 60 Hz.
Response: Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. The standard does not require any annual testing. The annual reset period for monitoring compliance should not be interpreted as a testing periodicity requirement. Frequency of verifications is to be addressed in the RRO's procedure. The commenter is encouraged to offer assistance in developing the regional procedure. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.			
Greg Mason – Dynergy Generation	Yes	No	1. NERC should not eliminate specifying a minimum verification frequency(every 5 years in the current standard).NERC should provide this guidance to the Regions. Regions can always be more stringent when regional needs require more frequent verification. Therefore, suggest adding "every five years" verification requirement in Sections B,R1. 2. Section D,2.1 should reference Section R1 instead of Section R2.2.
Response: Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response, which would also address periodicity of verification. The reference in D.2.1 was correct as stated in the 1st draft.			
Peter Burke – American Transmission Co.	Yes	No	R1. After "transients," add "and be sustained while frequency remains off normal." R2. change "within 30 days" to "within 30 calendar days."
Response: The word, 'transients' was replaced with 'deviations' and additional language was added to clarify that the data needs to address both initial and longer term frequency deviations. This supports the intent of your suggestion. The requirement to provide the information was modified so that the GO must provide the information in accordance with the RRO's procedures – and the RRO's procedures must address periodicity and schedule for the GO to report its information.			
Midwest Reliability Organization	Yes	No	Assume the standard allows for the RRO to approve of exemption for smaller units?

Commenter	Reliability Need	Acceptable Translation	Comments
			R1. After "transients", add "and be sustained while frequency remains off nominal". R2. Change "within 30 days" to "within 30 calendar days". Levels of non-compliance. Where "some" is used for non-compliance, is it possible to define further? Correct proposed effective date under A5 from October 1 to November 1.

Response: The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data.

The word, 'transients' was replaced with 'deviations' and additional language was added to clarify that the data needs to address both initial and longer term frequency deviations. This supports the intent of your suggestion.

The requirement to provide the information was modified so that the GO must provide the information in accordance with the RRO's procedures – and the RRO's procedures must address periodicity and schedule for the GO to report its information.

"Some information missing" simply means the data is not complete. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. That will delay implementation and the proposed effective date has been changed to, 'To be determined'.

Commenter	Reliability Need	Acceptable Translation	Comments
IESO – Ontario	Yes	No	R2.1 should be updated to include requirements to report the status immediately. Drafting Team should verify that the testing requirements that appear in the "S" language in the original Standard has been dropped. Is this intentional?

Response: The original Planning Measure was confusing because it implied both real-time reporting (by including the TOP as a recipient of the GO's information). The drafting team believes that the real-time measures belong in an 'operations' standard (TOP-006) and will ask stakeholders for confirmation.

The revised standard addresses data for modeling, not real-time operations.

The intent of the 'S' statement for IIB and III C have been translated into the new standards. The 'S' statements said:

> **II.B.S5.** Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.
>
> **III.C.S5.** Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

Commenter	Reliability Need	Acceptable Translation	Comments

The proposed standards require that generator data be verified, but don't require that 'testing' be used because there are other methods of verifying data. (Note that MOD-024 and MOD-025 address verification of gross and net real and reactive power capabilities; MOD-026 addresses verification of models and data for generator excitation system functions.) The proposed standard MOD-027 requires the generator owner to identify how its unit will respond to frequency deviations – and requires the generator owner to identify the method used to make this determination. This supports the intent of the 'S' statement for III C.

Commenter	Reliability Need	Acceptable Translation	Comments
Gerald Rheault – Manitoba Hydro	Yes	No	R2.1: Why aren't GOs required to report non-functioning or blocked speed/load governor controls immediately? As written, if there is not a request, the blocked speed/load governor would never be reported. R2.2: the frequency response test should be a physical test. Frequency of testing should be specified.

Response: The original Planning Measure was confusing because it implied both real-time reporting (by including the TOP as a recipient of the GO's information). The drafting team believes that the real-time measures belong in an 'operations' standard (TOP-006) and will ask stakeholders for confirmation.

Drafting team is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
SPP Generation Working Group	Yes	No	R2.1 To verify this data each individual unit will need to be tested. It is anticipated that part of this testing would include purposely tripping of the unit off line to obtain some data.. For this to occur, a high level of coordination is needed between the balancing authority, generation owner and pool. Extra caution must be taken with this type testing to help ensure the reliability of the system is not impacted and the unit is not damaged. Hence the frequency of this type test should be held to a minimum. R2.2 Same concerns as R2.1. Hence the frequency of this type test should be held to a minimum. Compliance: Many of these tests require the unit to be off line. Some units are scheduled to be on line over 18 months prior to an overhaul. Taking the unit off line, strictly for testing, could be very costly due to the replacement cost of energy might be natural gas as opposed to coal that the unit to be tested is burning. Hence the time between tests must to be longer then one year. If a company has similar units, we would propose that one unit be tested and those characteristics would be applied to other similar units in the company's fleet, similar to WECC's testing procedure. This testing will require sophisticated monitor equipment. GWG believes a minimum of a five year testing cycle is more appropriate

Commenter	Reliability Need	Acceptable Translation	Comments

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
FRCC	Yes	No	In R2.2. delete everything after the comma (including date conditions of the verification). This phrase only applies if there is a system event that the Generator Owners could use for verification.

Response: The date and conditions of verification are important information for verification.

Commenter	Reliability Need	Acceptable Translation	Comments
Mark Kuras – MAAC	Yes	No	Recommended new R3 - The Generator Owner shall provide the TP with information on any under frequency protection set at frequencies at or above the lowest stage of regional UFLS trip settings.
Multi-Regional Modeling Working Group	Yes	No	Recommended new R4 - If the governor and prime mover model does not conform to an IEEE standard or PSSE or PSLF/PSDS standard library model, generator owner shall be required to have a user-defined model written and validated. Delete text under Additional Compliance Information because it is up to the region as to how compliance will be measured. This text adds nothing to the standard.

Response: Coordination with UFLS does not apply to this standard, which is focused on verification of generator frequency response.

The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue. .

The compliance information identifies how compliance with NERC standards will be determined. If the compliance information indicates that compliance will be measured through annual self-certification, then that is how the Compliance Monitor must measure compliance with this standard. It is not completely up to the Region to determine how to measure compliance with NERC Standards.

Commenter	Reliability Need	Acceptable Translation	Comments
Joseph D Willson – PJM	No	No	Level 1 goes beyond the requirement by stating "verification" Level 3 can't be measured since Requirement 1 doesn't state what information is to be included. Level 4 is confusing and seems to try and catch four different elements of only two requirements

Commenter	Reliability Need	Acceptable Translation	Comments

Response: The drafting team is recommending that this standard be field tested. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
Individual Members of CCMC	Yes	No	Does Level 1 only address the “date and conditions of the verification”? Something more important to reliability seems to be missing. Level 3 can’t be measured since Requirement 1 doesn’t state what information is to be included. “Conditions” in R2.2 needs to be expanded so that compliance will be meaningful for reliability. Level 4 is confusing and seems to try and catch four different elements of only two requirements. It appears to be judging compliance on 4 issues. Rewording may be needed for clarity.

Response: The drafting team is recommending that this standard be field tested. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
NERC Interconnection Dynamics Working Group	Yes	No	Title needs to be changed: Verification of Generating Unit Primary Frequency Response — R1 – The Generator Owner shall provide modeling data to the…Organization requirements. The data shall be compatible with the standard speed governing system models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. — Add R3 as follows: The generating unit turbine-governor model data shall be provided to the TP and RRO. The above model/data shall be compatible with the standard speed governor models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. — Add R4 as follows: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days.

Response: This standard is addressing longer-term frequency response as well, not just primary (governor) response. Changed 'generator' to 'generating unit'.

The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into

Commenter	Reliability Need	Acceptable Translation	Comments

the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue..

Re-verification time constraints are to be addressed in the RRO procedure.

AEP			Reword the title as follows: Verification of Generating Unit Primary Frequency Response Add R3 as follows: The generating unit turbine-governor model block diagram and associated data shall be provided to the TP and RRO. The above model/data shall be compatible with the standard speed governor models available in stability programs widely used in the industry. If a new model is necessary for reasonable representation of the equipment, the new model must be developed for industry-wide use. Add R4 as follows: Any field changes made by the Generation Owner or Generator Operator to the verified data described in R1 above shall be re-verified / tested as soon as possible. Such changes, and their associated verification/testing results, shall be coordinated with the Transmission Owner, Planning Authority, and Transmission Planners, and reported to the region within 30 days. D1.2 Compliance Monitoring Period and Reset Timeframe: At installation of new equipment. Beyond that, when equipment is changed out or when setting changes are made. (Once this data becomes established and there are no further equipment changes, it is unnecessary and burdensome to keep repeatedly doing compliance reviews.) D1.3 Data Retention: Generator Owner shall retain commissioning and test reports and data indefinitely or until unit is retired. D1.4 Additional Compliance Information: The Generator Owner shall demonstrate compliance through transmitting the verified data to Transmission Owner/Operator/Planner, and through self-certification or audit - - - - as determined by the Compliance Monitor.The Generator Owner shall demonstrate compliance by handing over the requested data.

Response: This standard is addressing longer-term frequency response as well, not just primary (governor) response. Changed 'generator' to 'generating unit'.

The suggested requirements to improve consistency of the quantitative data reported, including use of IEEE standards can be incorporated into the RRO procedure. The drafting team does not believe there is sufficient consensus on these requirements for reporting of quantitative data to include in a NERC standard at this time and will ask stakeholders for feedback on this issue..

Re-verification requirements and time constraints are to be addressed in the RRO procedure.

Commenter	Reliability Need	Acceptable Translation	Comments

Data retention is for current and prior data. The drafting team believes that is sufficient.

The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
Raj Rana – AEP	Yes	Yes	See AEP Comment

Response: See AEP response.

Commenter	Reliability Need	Acceptable Translation	Comments
Michael C. Calimano – NYISO	Yes	Yes	In concept collecting this information has value, the actual testing required to validate the parameters may pose adverse reliability risks during testing

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

Commenter	Reliability Need	Acceptable Translation	Comments
WECC Reliability Subcommittee	Yes	Yes	WECC RS agrees with the removal of the five-year testing requirement and that it should be established by the RRO.
Mohan Kondragunta – Southern California Edison	Yes	Yes	

Response: The drafting team agrees.

Commenter	Reliability Need	Acceptable Translation	Comments
Barry Green – Ontario Power Generation	Yes		There is some inconsistency in this package of standards affecting generators, between applicability to generator owner in some cases and generator operator in others. For this standard, MOD-027-1, the applicability must lie with the generator operator. In many cases, the owner, by virtue of contractual obligations, would not have the ability to carry out the obligations imposed by this standard. In other cases, ownership could be shared and it would not be appropriate for these obligations to be shared. Therefore, the applicability of this standard more correctly belongs with the generation operator. Alternatively, if NERC chooses to be less prescriptive, it could, for the purposes of the standard, place an obligation on the owner or operator, with an obligation on the region to clarify in each case, the appropriate entity to meet the requirements.

Commenter	Reliability Need	Acceptable Translation	Comments

Response: The functional model assigns capability verification to the generator owner. The comment could be an issue when there are joint owners, but in these cases there are agreements to address delegation of this task among the owners.

John Horakh – MACC	Yes	Yes	Good conversion from prescribed testing to verification. However the Generator Owner may require significant time beyond November 1, 2005 for the initial verification. An effective date of five years beyond Board approval is more realistic.

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response. As envisioned, the standard's effective date would be phased in over several years.

PPL Corporation	Yes	Yes	PPL supports the objective of this proposed standard, which is to verify the status of generator primary frequency responses used in models for reliability studies. However, this objective will be severely hampered by the limited amount of information that the Generator Owner can provide, which consists of the governor gain setting (MW per Hz), the droop setting, a deadband setting, and perhaps a time constant. It is also unclear how these parameters could ever be verified in the field, inasmuch as it is not possible to stage the system frequency disturbances that would be required. PPL believes that while the proposed standard's goals are worthy, it may be attempting to achieve a level of modeling precision that is neither necessary nor achievable in practice. A blanket exemption for nuclear units is needed because nuclear regulations prevent these units from having active governor controls, which would override the licensed operators' control of nuclear reactors during system frequency disturbances.

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. The commenter is encouraged to offer assistance in developing the regional procedures.

John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Using the term verify is vague and subject to different interpretations by various entities. Unless specified in another Reliability Standard, a requirement should be added to require generator owners to notify the RA, BA, and/or TO as appropriate as soon as a non-functioning or blocked speed/load governor controls has been identified. The Levels of Non-Compliance as written are on a per generator basis, and will not work well

Commenter	Reliability Need	Acceptable Translation	Comments
			for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO, the levels of non-compliance should be rewritten as proposed in the comments provided by the SERC Planning Standards Subcommittee (PSS).

Response: The term, 'verify' has been used in several standards and seems to be accepted by most commenters. The acceptable methods of verifying the data must be identified in the Region's procedures.

The drafting team believes that requiring notification of the RA, BA and/or TOP of changes in real-time operating conditions is outside the scope of this standard, which is limited to modeling. There are other standards to address these types of real-time notifications. The original Planning Measure was confusing because it implied both real-time reporting (by including the TOP as a recipient of the GO's information). The drafting team believes that the real-time measures belong in an 'operations' standard (TOP-006) and will ask stakeholders for confirmation.

The drafting team is recommending that this standard be field tested. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
Resource Issues Subcommittee	Yes	Yes	Consider combining R1 and R2, as they seem to overlap

Response: R1 and R2 were merged into a new 'R3' to better organize the requirements.

Commenter	Reliability Need	Acceptable Translation	Comments
Joseph F. Buch – Madison Gas and Electric	Yes		R1 indicates that the generator owner is to provide information on the generator response to frequency transients, however, no information on what constitutes a frequency transient is provided. R2.2 indicates that the generator owner is to provide verification of the frequency response however no indication of test criteria is provided and no information on what sort of time resolution for plotting frequency vs load change is provided. Information on older or small units may not be available. It is recommended that this standard undergo field testing to better define the requirements. At the same time the benefits of providing data on small units (<50 MW) or those of older vintage should be evaluated).

Response: Drafting team agrees and is recommending a field test to determine appropriate methods to verify generator frequency response. Performance analysis from the August 2003 blackout may be useful in determining methods to verify frequency response.

The regional procedures are required to include generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the procedures for verifying generation equipment data. The commenter is encouraged to offer assistance in developing the regional procedures.

Commenter	Reliability Need	Acceptable Translation	Comments
SERC EC Planning Standards	Yes	Yes	Unless specified in another Reliability Standard, a requirement should be added to require generator owners to notify the RA, BA, and/or TO as appropriate as soon as a non-functioning or blocked speed/load governor controls has been identified. The Levels of Non-Compliance

Commenter	Reliability Need	Acceptable Translation	Comments
Subcommittee (PSS) Entergy	Yes	Yes	as written are on a per generator basis, and will not work well for entities that have a large number of generators. In addition, because the details of the requirements are left up to the RRO, the levels of non-compliance should be rewritten as follows: 2.1. Level 1: Verified generator data was provided and was complete for less than 100% of a generator owner's units as required by the RRO procedures. 2.2. Level 2: Verified generator data was provided and was complete for less than 95% of a generator owner's units as required by the RRO procedures. 2.3. Level 3: Verified generator data was provided and was complete for less than 90% of a generator owner's units as required by the RRO procedures. 2.4. Level 4: Verified generator data was provided and was complete for less than 85% of a generator owner's units as required by the RRO procedures.

Response: The drafting team believes this standard is focused on verification of model data, not real-time operating information. The original Planning Measure was confusing because it implied both real-time reporting (by including the TOP as a recipient of the GO's information). The drafting team believes that the real-time measures belong in an 'operations' standard (TOP-006) and will ask stakeholders for confirmation.

The drafting team is recommending that this standard be field tested. The compliance elements of the standard will be finalized following the field testing. The drafting team will ask for suggestions for the levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
Xcel Energy – Northern States Power	Yes	Yes	
SERC EC Generation Subcommittee (GS)	Yes	Yes	
Deborah M. Linke – US Bureau of Reclamation	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	

MOD-027-1 Verification of Generator Unit Frequency Response

Commenter	Reliability Need	Acceptable Translation	Comments
Rebecca Berdahll – Bonneville Power Administration	Yes	Yes	
Karl Bryan – Corp of Engineers			
Jay Sietz – US Bureau of Reclamation			
Brenda Anderson			
ISO/RTO Council Standards Review Committee	Yes	Yes	
Doug Hohbough – First Energy Corp.	Yes	Yes	
D. Bryan Guy – Progress Energy, Inc.	Yes	Yes	
Jerry Nicely – TVA Nuclear Generation	Yes	Yes	
Ed Riley – California ISO	Yes	Yes	
Howard Rulf - WE Energies	Yes	Yes	

MOD-027-1 Verification of Generator Unit Frequency Response

Commenter	Reliability Need	Acceptable Translation	Comments
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	

Comments on Field Test and Effective Date

Summary Consideration: The drafting team split MOD-023 and distributed the requirements for the RRO to develop procedures into the associated MOD-024 through MOD-027 standards. Based on the comments provided, the drafting team is recommending that this standard be field tested before it is finalized. An 'effective date' needs to be determined following an analysis of the field testing.

Members	Field Test Required?	Recommended Date?	Justification
Greg Mason – Dynergy Generation	Yes	7/1/07	First, per MOD-023-1 the Regions are required to determine generating unit exemption criteria to the data requirements(allow 6 months).Then for the affected units,this standard will require significant time and effort to go through data in archives to document the information(allow one year). To verify required governor data will also likely require unit testing during unit start or shutdown.
Response: The requirement for the RRO to develop procedures for verification and status of generator frequency response were moved from PRC-023 into PRC-027. The drafting team agrees that there needs to be a time delay between the time that the RRO develops the procedures and the time the Generator Owners meet the RRO's requirements. The drafting team envisions that if the results of field testing show that the standard should continue to be developed and implemented, the effective date for the Generator Owners to become compliant will be phased in over several years.			
Midwest Reliability Organization	Yes		Delay necessary for method standardization in MOD-023-1. Additionally, field testing and/or some external evaluation and additional costs may be necessary.
Response: The requirement for the RRO to develop procedures for verification and status of generator frequency response were moved from PRC-023 into PRC-027. The drafting team agrees that there needs to be a time delay between the time that the RRO develops the procedures and the time the Generator Owners meet the RRO's requirements. The drafting team envisions that if the results of field testing show that the standard should continue to be developed and implemented, the effective date for the Generator Owners to become compliant will be phased in over several years.			
Southern Company Generation	Yes		SoCo Generation recommends this standard be better defined to develop practical and safe methods of collecting the required verification data. If this standard is adopted then we recommend field testing as stated in our comment on MOD-024-1 above.
Response: The drafting team modified the requirements so they should be better defined. Under the Reliability Standards Development Process, field testing is conducted before the standard is finalized. The drafting team envisions that if the results of field testing show that the standard should continue to be developed and implemented, the effective date for the Generator Owners to become compliant will be phased in over several years.			
Southern Company – Transmission	Yes		Southern Company Transmission recommends this standard be better defined to develop practical and safe methods of collecting the required verification data. If this

			standard is adopted then we recommend field testing as stated in our comment on MOD-024-1 above.
Response: The drafting team modified the requirements so they should be better defined. Under the Reliability Standards Development Process, field testing is conducted before the standard is finalized. The drafting team envisions that if the results of field testing show that the standard should continue to be developed and implemented, the effective date for the Generator Owners to become compliant will be phased in over several years.			
Carol L. Krysevig – Allegheny Energy Supply Co.	No		As long as 'testing' is not a stated requirement for verification no delay in implementation is required. If MOD-027-1 is linked to MOD-023-1 then the effective date should also be the same.
Response: The revised proposed standard does not require 'testing' as the only method of verification. The requirement for the RRO to develop procedures for verification and status of generator frequency response were moved from PRC-023 into PRC-027. The drafting team agrees that there needs to be a time delay between the time that the RRO develops the procedures and the time the Generator Owners meet the RRO's requirements.			
Xcel Energy – Northern States Power	Yes	1/2008	This is an extension of MOD-023-1. At present, there is no industry-wide accepted criteria to perform this function, and the methodology would need to come from the respective RRO process described in MOD-023 - 1. Implementation and field testing could only take place after that.
Response: The requirement for the RRO to develop procedures for verification and status of generator frequency response were moved from PRC-023 into PRC-027. The drafting team envisions that if the results of field testing show that the standard should continue to be developed and implemented, the effective date for the Generator Owners to become compliant will be phased in over several years.			

VAR-001-1 Voltage and Reactive Control (Revision of VAR-001-0)

Commenter	Reliability Need	Acceptable Translation	Comments
IESO			(From Q 4 – Other comments) R1. We suggest changing the reference of MVAR as Mvar, as this is a SI abbreviation. R10.2 We suggest addition of a requirement/obligation for the Generator Operator to log information and times where they needed to run the generator to control power factor or reactive power.
Response: The drafting team will make the abbreviations consistent. The drafting team can not determine a reliability need for this addition in R10.2.			
Carson Taylor – Bonneville Power Administration			As noted by IDWG, another standard is needed for automatic control of voltage and reactive power. Best practice is to rely primarily on automatic control, realizing that disturbances can evolve to blackouts within seconds or a few minutes—before operators can take action.
Response: Thank you for your comment. Please submit a SAR for the referenced proposed standard.			
Peter Burke – American Transmission Co.	Yes	No	We fully support moving R9.1 and R9.2 to VAR-002. V1 of this standard should be enhanced to include Measures that address all the Requirements R1--R12 comprising it. While the translation resulting in R3, R10, R11 and M1-M3 is acceptable, not fixing the pre-existing deficiencies (i.e. absence of any Measures) in the V0 standard makes the resulting VAR-001-1 an incomplete V1 revision.
Response: Thank you for your comment. Modifying the standard to include measures for existing V0 requirements is outside the scope of the subject SAR.			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	Would like the vebiage to read either Generator Owner or Transmission Owner to supply this information. In our company, the Transmission Operator keeps the official records.

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td colspan="4">Response: R10 was dropped because writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002.</td></tr>
<tr><td>Kansas City Power and Light</td><td>Yes</td><td>No</td><td>Added new requirements and revised several others. There is currently no standard that addresses voltage stability analysis and associated limits.</td></tr>
<tr><td colspan="4">Response: The drafting team cannot respond to this comment due to insufficient information. Please submit a SAR for the referenced proposed standard.</td></tr>
<tr><td>Mark Kuras – MAAC</td><td>Yes</td><td>No</td><td>All requirements are not dealt with in measures and levels of non-compliance.</td></tr>
<tr><td colspan="4">Response: Modifying the standard to include measures for existing V0 requirements is outside the scope of the subject SAR.</td></tr>
<tr><td>Kenneth Dresner – FirstEnergy Solutions</td><td>Yes</td><td>No</td><td>1. The standard is well written but the 5 day time frame to respond to R5 is to short The number of transformers can amount to the hundreds and a response time of 30 business days seems more appropriate.
2. Also the definition of Auxiliary transformer needs to be clear.
3. I believe that by merging of the standards will make the tracking of compliance more difficult. The issue of being noncompliant on one Requirement will roll up to the noncompliance to the overall standard This will make physically tracking the compliance levels more difficult</td></tr>
<tr><td colspan="4">1. Response: VAR-002 R5 was revised and now states the GOP has 30 calendar days to provide a response.
2. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001. Therefore, the term, ‘auxiliary transformer’ is not used in the revised standard.
3. Eventually, measures and non-compliance will be added to all the requirements from Version 0.</td></tr>
<tr><td>Xcel Energy – Northern States Power</td><td>Yes</td><td>No</td><td>Requirement R2 - "shall acquire" is a financial term, not a guidance term. Recommend change to "shall maintain".
Requirement R5.1 - "shall notify the Generator Operator of a voltage schedule or reactive</td></tr>
</table>

Commenter	Reliability Need	Acceptable Translation	Comments
			output " is not clear. Recommend change to " the Transmission Operator shall direct the Generator Operator to either maintain or change its voltage schedule or reactive output as necessary"
Response: R2 is from the original V0 approved standard and making modifications unrelated to the Phase III & IV measures is outside the scope of the subject SAR. The draft standard (now R6.1) was modified based on your comments and uses the term, 'direct'.			
Greg Mason – Dynergy Generation	Yes	No	1. Section B,R3-Suggest deleting reference to "reactive schedule"-a "voltage schedule" is the practical requirement that should be provided to the Generation Operator. 2. Section B,R3-Suggest clarifying that a voltage schedule is a range of voltage(not a specific voltage) and that voltage schedule should take into account voltage measuring accuracy and the dynamics of system voltage. The voltage schedule must also be a range of voltage(not a specific voltage) in order to comply with the R3 provisions of VAR-002-1. 3. We agree with moving R9.1 and R9.2 to VAR-002. 4. In Section B, R11 change the word "instructing" to "requiring"(consistent with the current standard). 5. There should be a "Requirement" added for the Transmission Operator to develop and provide a procedure to the Generator Operator regarding the R3 provisions of VAR-002.
Response: R3. is written properly as it provides options to specify reactive needs to generators. There are TOPs who are providing GOPs with directions based on a reactive schedule. Either a specific voltage with tolerances or a voltage range can be used for a voltage schedule. R9.1 and R9.2 were moved to VAR-002 as suggested. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001. Writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002.			
IESO – Ontario	Yes	No	Questions are raised regarding the dropping of Generator Operators from this standard. It seems that there is a lot of responsibility placed on the Generator operators to notify the Transmission operators. Moreover, in addition to requirements laid down in section 9.1 & 9.2 of VAR-001 there are other requirements given in section R3 & R5 etc that necessitates the retention of Generator operator application in this standard.

Commenter	Reliability Need	Acceptable Translation	Comments
			R2 should refer to Table 1 in TPL-001-0 to 004-0 for those contingency conditions that shall be considered.
Response: R3 and R5 are the responsibility of the TOP not the GOP. The Generator Operator tasks were moved to VAR-002. R2 is an existing V0 requirement and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. In addition, the TPL-001 through TPL – 004 standards deal with long term planning, whereas R2 of this standard deals with the real – time near term operating horizon.			
Brandon Snyder – Duke Energy	Yes	No	Requirement 6 is not a requirement. It is an understood entitlement of power. R11.2 should encompass entire standard. R5 should not contain all generators, the RRO should define exemption criteria.
Response: R6 is a Version 0 requirement and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. All of the requirements to develop procedures were removed from the standard so the need to identify exemptions from compliance with procedures no longer exists. . R5 is an existing Version 0 requirement, and making modifications is outside the scope of the SAR. The drafting team did add a requirement for the TOP to identify generators exempt from following voltage and reactive schedules.			
Pacific Gas and Electric Richard Padilla Greg Reimers			R7 The basis for the requirement should be expanded "… to maintain system, interconnection, and nuclear power plant offsite power voltages within established limits."
Response: Maintenance of system voltages within established limits encompasses nuclear plant offsite power voltages therefore no expansion of R8 (previously R7) is required. In addition, R7 is a Version 0 requirement, and making modifications to Version 0 requirements is outside the scope of this SAR.			
Mohan Kondragunta – Southern California Edison	Yes	No	SCE agrees with moving 9.1 and 9.2 to VAR-002-1 R10. In the WECC this requirement is handled through RMS and R10 would require new procedures are agreed to by Generators in the WECC. Change to read: "Each Transmission Operator, Balancing Authority or Reliability Authority with synchronous generation …"
Response: The drafting team has moved R9.1 and R9.2 as suggested.			

Commenter	Reliability Need	Acceptable Translation	Comments
R10 was dropped because writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002.			
SPP Transmission Working Group	Yes	No	No timeline for voltage schedules. R12 – no standard for NERC Voltage Stability Analysis in associated limits.
Response: The drafting team does not have sufficient information to respond to the first comment. Please submit a SAR for the referenced proposed standard.			
Southern Company Generation	Yes	No	We believe the generator operator requirements R9, R10, and R11 should be deleted from VAR-001-1 and addressed separately from the Transmission by placing it in VAR-002-1 and reworded more appropriately.
Response: Requirements R9.1 and 9.2 have been moved to VAR-002. R10 was dropped because writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001.			
Jerry Nicely – TVA Nuclear Generation SERC EC Generation Subcommittee (GS) D. Bryan Guy – Progress Energy, Inc.	Yes Yes	No No	All generator operator requirements should be removed from VAR-001-1 and reconciled with the requirements in VAR-002-1. Strike the words and auxiliary from all sections of the standard.
Response: The drafting team moved all GOP requirements to VAR-002 as suggested. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing			

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td colspan="4">standard MOD-010 and was removed from VAR-001. Therefore, the term, ‘auxiliary transformer’ is not used in the revised standard.</td></tr>
<tr><td>Tennessee Valley Authority</td><td>Yes</td><td>No</td><td>All generator operator requirements should be removed from this standard and reconciled with the requirements in VAR-002-1 and if not, then generator operators should be added in the Applicability Section. Strike the words “and auxiliary” from all sections.

R4 mentions Marketers, but there is no mention in the Compliance section.

R6 and R7 are redundant. Delete R6</td></tr>
<tr><td colspan="4">Response: The drafting team moved all GOP requirements to VAR-002 as suggested.

R4 is a requirement for the Purchasing-Selling Entity and was approved as a Version 0 Requirement –making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR.

R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001. Therefore, the term, ‘auxiliary transformer’ is not used in the revised standard.

R6 (now R7) and R7 (now R8) are Version 0 requirements and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR.</td></tr>
<tr><td>Resource Issues Subcommittee</td><td>Yes</td><td>No</td><td>1. R5 should allow for alternatives to the open-circuit step response test, such as on-line transient data collection methods.

2. RIS believes that consideration should be given in this standard to collecting the appropriate data to verify that units will perform as simulated. All of the information requested in R3 may not be necessary, and should not be required unless specified by the Region.</td></tr>
<tr><td colspan="4">Response: The drafting team believes the RIS is referencing the wrong standard.</td></tr>
<tr><td>NERC Interconnection Dynamics Working Group</td><td>Yes</td><td>No</td><td>1. Change the Title to: Operational Voltage and Reactive Control —

2. This standard appears to be aimed at the operator…a number of changes should be made to Standard VAR-003 to specifically address automatic voltage and reactive control from a planning perspective. —

3. Modify R.2 – Clarify what is meant by contingency conditions…R8 limits it to single contingencies, which are often not sufficient for analysis and operations.

4. R5.1 – Remove phrase: to maintain Interconnection and generator stability.</td></tr>
</table>

Commenter	Reliability Need	Acceptable Translation	Comments
			5. R5 – Add the terms …and availability… after the word status 6. — Reword R10.4 to read: Specify narrowly defined criteria by which generators are to be exempted from the above requirements, for example, to allow for temporary operating conditions. a. Having a general exemption clause weakens the standard and causes loopholes. 7. — R8 should be modified to read: …voltage under next contingency conditions… First appears to be a typo and appears to be confusing…the next contingency is the first contingency from the current operating condition.
Response: 1. The drafting team believes the title is appropriate and since most commenters did not object to the title, no change was made.. 2. Comments regarding VAR-003 should be addressed in the VAR-003 standard comments. 3. R2 is a requirement from the original V0 Standard and making the suggested modification is outside the scope of the subject SAR. 4. R5.1 (now R6.1) was modified as suggested to remove the explanatory phrase. 5. Availability is included as part of status. 6. The drafting team revised the standard so that the only exemption criteria that is relevant is in the requirement for the TOP to identify synchronous generating units that are exempt from following a voltage or reactive schedule. The suggested specific language wasn't adopted as it would be difficult to assess 'narrowly defined'. 7. R8 is a requirement from the original V0 Standards and making the suggested modification is outside the scope of the subject SAR.			
Southern Company – Transmission	Yes	No	Revise R9.1. Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of each voltage regulator and power system stabilizer, within 30 minutes or via real time SCADA as determined by the TO
Response: In response to the industry comment R9.1 will be moved to VAR-002-1. Adding, 'via real time SCADA as determined by the TOP' does not enhance the requirement as SCADA signals should be received within 30 minutes and the TOP is directed to provide the GOP with a procedure as defined in R10. VAR-002-1 does include a 30-minute requirement.			
Joseph D Willson	Yes	No	Level 1 Only deals with reporting stuff and not with real-time operations.

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td>– PJM</td><td></td><td></td><td>Level 2 Only Requirement 10 talks about exemptions.

Level 3: unsure what is being measured. Is it any directive from the TO that is being measured versus real-time voltage/reactive? What amount of data are we talking about.

R3 needs to be re-written to state “Each TO shall specify a voltage schedule, voltage range, Reactive schedule, or reactive range for operations to be …”

The standard has many good requirements. However, the measures and therefore compliance levels

Any exemptions must be in the Regional Differences Section of the standard</td></tr>
<tr><td colspan="4">Response:

All levels of non-compliance were revised to align with the revised requirements and measures.

The drafting team believes a specific voltage, a specific voltage with tolerances, or a voltage range is used for a voltage schedule so the drafting team believes no clarification of the term voltage schedule is required.

The drafting team is limited to making modifications related to the Phase III & IV Measures. Adding measures and compliance elements for the Version 0 requirements unrelated to the Phase III & IV Measures is outside the scope of the SAR.

The revised standard only requires the TOP to identify synchronous generating units exempt from following a voltage or reactive schedule. No Regional Differences have been identified.</td></tr>
<tr><td>Individual Members of CCMC</td><td>Yes</td><td>No</td><td>Level 1 Only deals with reporting documentation and not with real-time operations as required by much of the standard.

Level 3: unsure what is being measured? Is it any directive from the TO that is being measured versus real-time voltage/reactive? What amount of data is required?

This draft creates a standard made up from an incomplete V0 standard and 3 Phase 3 – 4 planning measurements. The result is confusing unless the original V0 requirements/measures/levels of non-compliance can be modified. It would be more complete and accurate if the proposed standard only merged Phase 3-4 planning measurements.

R3 needs to be re-written to state “Each TO shall specify a voltage schedule, voltage range, Reactive schedule, or reactive range for operations to be …”

The standard has many good requirements. However, the measures and therefore compliance levels need to reflect them.</td></tr>
</table>

Commenter	Reliability Need	Acceptable Translation	Comments
			It may be more appropriate to include any exemptions in the Regional Differences Section of the standard..
Response: All levels of non-compliance were revised to align with the revised requirements and measures. The drafting team believes a specific voltage, a specific voltage with tolerances, or a voltage range is used for a voltage schedule so the drafting team believes no clarification of the term voltage schedule is required. The drafting team is limited to making modifications related to the Phase III & IV Measures. Adding measures and compliance elements for the Version 0 requirements unrelated to the Phase III & IV Measures is outside the scope of the SAR. The revised standard only requires the TOP to identify synchronous generating units exempt from following a voltage or reactive schedule. No Regional Differences have been identified.			
PPL Corporation	Yes	Yes	PPL believes that a NERC standard should require all Generator Owners to have their Automatic Voltage Regulators (AVRs) in service and to immediately report any AVR outages to the system operator.
Response: Agree, however exemptions to the AVR reporting requirements should be allowed.			
Karl Kohlrus - City Water, Light & Power	Yes	Yes	There should be a provision that AVR should be able to be turned off if the machine is operating at its limit. Prior to the August 14, 2003 blackout, Eastlake 5 was operating at maximum real and reactive output. Since it was in AVR mode, it tripped when it tried to produce even more VARs than it was capable of producing when the voltage declined further.
Response: Agree, exemptions to the AVR reporting requirements should be allowed.			
WECC Reliability Subcommittee	Yes	Yes	WECC RS agrees with moving 9.1 and 9.2 to VAR-002-1
Response: Thank you. The drafting team has made the change based on industry support.			
Doug Hohbough – First Energy Corp.	Yes	Yes	Proposed move of sections to VAR-002-1 is ok.
Response: Thank you. The drafting team has made the change based on industry support.			

Commenter	Reliability Need	Acceptable Translation	Comments
John Horakh – MACC	Yes	Yes	Ok to move R9.1 and R9.2 to VAR-002
Response: Thank you. The drafting team has made the change based on industry support.			
NPCC CP9 RSWG Alan Adamson - NYSRC Consolidated Edison Vinod Kotecha Kathleen Goodman – ISO-NE	Yes Yes Yes Yes Yes	Yes Yes Yes Yes Yes	R2 should refer to Table 1 in TPL-001-0 to 004-0 for those contingency conditions that shall be considered.
Response: R2 is an existing Version 0 requirement, and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. In addition, TPL-001 through TPL – 004 deal with long term planning, whereas R2 of this standard deals with the real – time near term operating horizon.			
Michael C. Calimano – NYISO	Yes	Yes	R2 should refer to Table 1 in TPL-001-0 to 004-0 for those contingency conditions that shall be considered. R3 should apply to all generators and not just synchronous generators. R9 NYISO recommends evaluating TOP-004-0 to determine if this requirement is captured within the IROL and SOL requirements. Consider incorporating the necessary language into the TOP-004 standard and deleting R9. R9.1 would be more appropriate as R10.1 R9.2 is addressed in VAR-002-1 and should removed. R11.2 does not have a valid purpose and should be removed from VAR-001-1. R12 should be in TOP-004 and be removed from VAR-001-1

Commenter	Reliability Need	Acceptable Translation	Comments
			There are requirements without measurements. All requirements should have measurements.
Response: R2 is an existing Version 0 requirement, and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. In addition, In addition, TPL-001 through TPL – 004 deal with long term planning, whereas R2 of this standard deals with the real – time near term operating horizon. Induction generators generally cannot provide VAR support, so they shouldn't be included in R3.. R9 is an existing Version 0 Requirement and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. The drafting team moved R9.1 and R9.2 to VAR-002-1 as supported by industry commenters. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001. Therefore, the term, 'auxiliary transformer' is not used in the revised standard. R12 is an existing Version 0 Requirement and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. Adding measures for existing V0 requirements is outside the scope of the subject SAR.			
FRCC	Yes	Yes	Need to define voltage or reactive schedule and use consistently in the standard. Delete R9.1 and R9.2 and re-word R5 to include clearly defined requirements of the Transmission Operators and Generator Operators. Generator Operators should be required to determine the reactive setpoint required to maintain generator stability, not Transmission Operators. Clearly delineate the responsibilities for interconnection stability (Transmission Operator) and generator stability (Generator Operator). R3, R10 and R11 need to be re-written to clarify the intended requirements.
Response: The drafting team believes a specific voltage, a specific voltage with tolerances, or a voltage range is used for a voltage schedule so the drafting team believes no definition of the term voltage schedule is required. The drafting team believes it has applied voltage and reactive schedule consistently throughout the standard. The drafting team has moved R9.1 and R9.2 to VAR-002-1 as supported by the industry. R5 deals with an approved V0 requirement and modification is not within the scope of this SAR. All references to generator stability were removed from the revised standard.			

Commenter	Reliability Need	Acceptable Translation	Comments
R10 was dropped because writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001. Therefore, the term, 'auxiliary transformer' is not used in the revised standard. R3 was not modified as it was part of the approved V0.			
Gerald Rheault – Manitoba Hydro	Yes	Yes	This standard should apply to all generators, not just synchronous generators. R2: How does one measure if reactive resources are sufficient? Also, clarify contingency conditions- Cat B, C & D? R8: requires reactive resources to support voltage under first contingency. Does this conflict with R2? The wording in R3 should be modified so it is not mandatory for each generator to have a voltage schedule. For vertically integrated utilities the process of managing voltage and reactive control may be performed in a way such that a voltage schedule for each generator is not actually produced and communicated through a formal process which should be acceptable.
Response: Induction generators generally cannot provide VAR support. R2 and R8 are existing Version 0 requirements, and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. The Standard was revised to require the TOP to identify generating units that are exempt from following a voltage or reactive schedule.			
Midwest Reliability Organization	Yes	Yes	Move VAR-001-1 R9.1 and R9.2 to VAR-002 R1.1 and R1.2 so that all Generator Owner requirements are together. D2.2.2 and D2.2.3 can "incomplete" be defined as a measurable quantity? In R3, after "Each Transmission Operator shall", add the words "maintain a list of synchronous generators that are required to follow a voltage schedule, and". It should not be mandated that every unit have a voltage schedule developed for it. Also, this allows for the deletion of R3.1, which then becomes redundant. Note that without any change, R3 seems to indicate all generators must have a voltage schedule, while R3.1 seems to indicate only some need a schedule. Add a M4 that reads "In the event a voltage collapse occurs, the Purchasing-Selling Entity or

Commenter	Reliability Need	Acceptable Translation	Comments
			Transmission Operator shall, within 30 calendar days of a request, provide documents to the Regional Reliability Organization and NERC demonstrating the actions it took under R2 (TO), R4 (PSE), R6 (TO), R8 (TO), and R12 (TO) to prevent the voltage collapse." Corresponding language should also be added under Level 4 of the Non Compliance language.
Response: The drafting team moved R9.1 and R9.2 to VAR-002-1 as supported by the industry. The expectation for being in compliance would be 100% information anything less would be incomplete. Note that the levels of non-compliance were revised to align with the revised requirements and measures and the term, 'incomplete' is not used in the revised standard. The Standard was revised to clarify that the TOP must identify which generating units are exempt from following a voltage or reactive schedule. This supports your suggestion. The suggested addition of M4 and associated non-compliance is outside the subject SAR because it would be a measure for a Version 0 Requirement.			
Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	Yes	Within WECC the requirements of R10 have been communicated to the generation owners via the RMS. Provide additional clarity to R4 to avoid possible misinterpretations of this requirement. Is the Transmission Provider to provide the reactive quantity to the PSE for each transaction? What PSE documentation is NERC requiring to document this requirement has been met? The applicability statement does not include the Transmission Provider.
Response: The drafting team removed R10 from the revised standard. R10 was dropped because writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002. The drafting team notes that modification to R4 would be a change to an approved portion of a V0 requirement and is outside the scope of the subject SAR. The comment regarding the transmission provider and PSE is not within the scope of this SAR.			
Deborah M. Linke – US Bureau of Reclamation	Yes	Yes	Within WECC the requirements of R10 have been communicated to the generation owners via the RMS.

Commenter	Reliability Need	Acceptable Translation	Comments
Response: The drafting team removed R10 from the revised standard. R10 was dropped because writing procedures that identify steps for the Generator Owner or Operator to take would be redundant with the requirements already in existence in VAR-002.			
SERC EC Planning Standards Subcommittee (PSS) Entergy John K. Loftis, Jr. – Dominion – Electric Transmission	Yes Yes Yes	Yes Yes Yes	Suggest that R6 be deleted since all the R6 requirements are included in R7. The PSS agrees with moving R9/1 and R9/2 to VAR-002.
Response: R6 is an exiting Version 0 requirement and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR. The drafting team moved R9.1 and R9.2 to VAR-002.			
Raj Rana – AEP	Yes	Yes	Change the title to Real Time Voltage and Reactive Control. This is to reflect the focus of this standard, which is in the transmission operations arena. Reword R8 as follows: Each Transmission Operator shall maintain reactive resources to support its voltage under credible contingency conditions. (This allows looking at n-1 as well as multiple contingencies.)
Response: The drafting team believes the title is appropriate and since most commenters did not object to the title, no change was made.. R8 is an existing V0 requirement and making modifications to V0 requirements that aren't related to the measures in Phase III & IV is outside the scope of the subject SAR.			
Transmission Issues Subcommittee	Yes	Yes	R2 should clarify that the Contingency conditions are those contingencies described in Table 1 of NERC standards TPL-001, 002, 003, and 004. "synchronous" should be removed and R3 should apply to all generators.

Commenter	Reliability Need	Acceptable Translation	Comments
			R8 only refers to first contingencies. The drafting team should confirm whether that is the intent of this Requirement. R12 should provide guidance to the TO on anticipating contingencies, such as Category D from Table 1 of the TPL standards, that could lead to voltage collapse.
Response: The drafting team notes that modification to R2, R8, and R12 would be a change to an approved portion of a V0 requirement and is outside the scope of the subject SAR. In addition, the contingencies in Table 1 are intended for use in the planning horizon, not in the operating horizon. Induction generators generally cannot provide VAR support, so R3 was not modified.			
Transmission Subcommittee			1. VAR-001-1, A. Introduction, 4. Applicability, TS recommends adding "4.3. Transmission Service Provider" - TS: TSP is used in R4. 2. VAR-001-1, R3, TS recommends adding language for technical accuracy as follows: Each Transmission Operator shall "maintain a list of synchronous generators and shall (add)" specify a voltage or reactive schedule . . . TS recommends deleting R3.1, with additional language inserted into R3 3. VAR-001-1, R8.1., TS recommends the following language change: Each Transmission Operator "disperse and locate (delete)" "direct the operation of (add)" of reactive resources so that . . . 4. VAR-001-1, R9., TS recommends evaluating TOP-004-0 to determine if this requirement is captured within the IROL and SOL requirements. Consider incorporating the necessary language into the TOP-004 standard and deleting R9. 5. VAR-001-1, R9.1, TS recommends moving R9.1 to R10.1, since it is more appropriate under R10. 6. VAR-001-1, R9.2, TS recommends deleting R9.2, since it is essentially captured in VAR-002-1. 7. VAR-001-1, R11.2, TS Comment: R11.2 doesn't seem to have a valid purpose. R11.2 should either be deleted, or language should be added to clarify its purpose/intent. 8. VAR-001-1, R12, TS recommends evaluating TOP-004-0 to determine if this requirement is captured within the IROL and SOL requirements. Consider incorporating the necessary language into the TOP-004 standard and deleting R12.

Commenter	Reliability Need	Acceptable Translation	Comments
			9. TS Observation: There are requirements that do not have measures. The TS was under the impression that all requirements needed to have measures to meet the criteria of the Standards Process Manual. 10. VAR-001-1, M4, TS Recommendation and Consideration: TS Recommends adding M4 as follows: "M4. In the event a voltage collapse occurred on the bulk electrical system under the control of the Transmission Operator during the performance period, the Transmission Operator shall produce documents, within 7 calendar days, demonstrating the actions it took under VAR-001-1, R2, R6, R8, and R12, in an effort to prevent the voltage collapse." 11. VAR-001-1, M4, TS Consideration: TS recommends evaluating Measure M4 for inclusion within TOP-004, and remove the measure from this standard. 12. VAR-001-1, D. Compliance, 2.4., Level 4: TS recommends adding the following second paragraph to VAR-001-1, 2.4., "In the event a voltage collapse occu8rs, if the Transmission Operator has inadequate documentation demonstrating it took proper preventative actions under VAR-001-1, R2, R6, R8, and R12." 13. VAR-001-1, Compliance, 2.4., Level 4, TS Consideration: TS recommends evaluating Compliance Level 4 language for inclusion within TOP-04 and remove the Level 4 language from this standard.

Response:

1. The drafting team notes that modification to the Applicability section would be a change to an approved portion (R4) of a V0 requirement and is outside the scope of the subject SAR. Note that in R4, the TSP's actions are not a requirement for the TSP.
2. R3 was modified to the following: "Each Transmission Operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator, within applicable Facility Ratings, at a specified bus and shall provide this information to the Generator Operator. "

3,4. Modifying existing Version 0 requirements (R8, R9, R12), and adding measures and non-compliance for Version 0 requirements that are unrelated to the measures in Phase III & IV is outside the scope of the subject SAR.

5,6. The DT revised moved R9.1 and R9.2 to VAR-002-1 as supported by most commenters.

7. R11 was dropped because the requirement to write a procedure requiring the Generator Owner to provide this data was redundant with existing standard MOD-010 and was removed from VAR-001. Therefore, the term, 'auxiliary transformer' is not used in the revised standard.

8. R12 is an existing Version 0 requirement and making modifications to already approved Version 0 Requirements that are not directly related to the Phase III & IV Measures is outside of the scope of the current SAR.

9,10. The drafting team is limited to making modifications related to the Phase III & IV Measures. Adding measures and compliance elements

Commenter	Reliability Need	Acceptable Translation	Comments
for the Version 0 requirements unrelated to the Phase III & IV Measures is outside the scope of the SAR. 11,12,13. The drafting team modified the standard's measures and levels of non-compliance to align with the revisions to the requirements. Note that most of the suggested changes are outside the scope of the SAR .			
Joseph F. Buch – Madison Gas and Electric	Yes		
Samuel W. Leach – TXU Power	Yes	Yes	
Ed Riley – California ISO	Yes	Yes	
ISO/RTO Council Standards Review Committee	Yes	Yes	
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	Yes	
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Howard Rulf - WE Energies	Yes	yes	

Commenter	Reliability Need	Acceptable Translation	Comments

Les Pereira P.E.

General Comments Related to VAR-001-1, VAR-002-1, VAR-003-1 Standards

The VAR series of NERC Standards: VAR-001-1, VAR-002-1, VAR-003-1 on Voltage and Reactive Control, Generation Operation and Planning Assessment are one of the most important of the NERC Standards and touch upon one of the most difficult topics in system planning and operation today, namely to ensure that system reactive resources are “adequate” or “sufficient” to plan and operate the system so that voltage stability is ensured.

The three standards collectively have failed to :

1. Properly recognize, define and quantify “adequate” or “sufficient” reactive resources;
2. Describe how these are measurable in real-time and so indicated to the operator;
3. Differentiate the special requirements for “emergency” operation that require special approaches in real-time versus “normal” states of the system.
4. Make it clear what are the precise roles of the various entities: Transmission Operators/Purchasing-Selling Entities, Generator Operators and Transmission Planner/Planning Authority to ensure supply of adequate reactive resources, particularly during emergencies.

Given the importance of voltage control and reactive reserves and the role it played in the last three major blackouts : the July and August 1996 blackouts in the Western Interconnection and the August 2003 blackout in the Eastern Interconnection, it behooves NERC to seriously examine the adequacy of its VAR standards in addressing a difficult and contentious issue. Numerous smaller events also illustrate the effects on reliability of MVAR deficiency on a smaller scale than the larger blackouts. Indeed the rules and approaches in recognizing the importance and difficulty of reactive power assessment and supply need to be reassessed. FERC has recognized this, has taken the lead, and issued a comprehensive report which is the best first step in addressing the real MVAR requirements that the system needs to have to operate reliably and efficiently and the need for the industry/market to realize its importance. Now it is NERC’s turn to likewise recognize the crucial role of voltage control and reactive power for voltage stability and include special requirements in NERC Standards. (The term MVAR is used in these comments to mean ‘reactive power’).

Emergency Conditions need Special Requirements

The proposed draft of NERC Standards VAR-001-1, 002-1, and 003-1 essentially describe basic “good utility” practices that are applicable and generally work well when operational conditions are “normal” including regular N-1 contingencies. These requirements are such that any Transmission Operators/Purchasing-Selling Entities, Generator Operators, and Transmission Planner/Planning Authority could meet under those conditions. The standards require that: “Each Transmission Operator shall acquire “sufficient” reactive resources within its area to ensure “adequate” voltage levels under normal and Contingency conditions.” (From R2 of VAR-01-1, quotation marks added). When a blackout occurs, the involved entities can take refuge in the lack of specificity of the standards to defend their case. Adding the words “and if necessary load shedding” does not make the standard any stronger, because the necessary specificity to the operator to determine the circumstances when to resort to load shedding is not provided. Load shedding decisions cannot be taken lightly. If delayed too long, conditions could lead to blackouts. If done too early, the operator will face the inevitable recriminations and pay for potential liabilities. Hence the Standards should have special provisions for operation in emergency conditions. This is explored further later.

Dynamic vs. Static Reactive Power Sources Must be Recognized in the Standards

Static reactive power is supplied by static devices such as shunt or series capacitors, and the capacitance of the lines. Dynamic reactive power is supplied by dynamic machines such as synchronous generators or condensers. Static var compensators because of automatic controls are also classified as 'dynamic'.

The factors of location, MVAR quantity, quality i.e. static or dynamic, and the time, season, and system operating conditions, all directly affect the 'adequacy' and 'effectiveness' of reactive power reserves.

Shunt capacitors are a cheap source of MVAR supply. It works well when voltages are normal. However, the quantity of MVARs supplied by shunt capacitors is directly proportional to the square of the voltage. Hence as the voltage plunges, so does the effectiveness of shunt capacitors. Eg at 90% voltage, the shunt capacitor will put out only 81% of the rated MVARs. This becomes more and more critical as loads peak and voltages deteriorate in voltage instability prone areas during emergency conditions. As line flows increase, MVAR flow through lines increase as voltages decrease and MW losses increase. This gets worse as key lines or generators trip in the MW and/or MVAR deficient area. The end comes usually suddenly as voltage drops (at 80% voltage, the shunt capacitor MVARs is just 64% of rated) and may likely be controlled only by load-shedding.

The total of the static and dynamic capability should exceed the total MVARs 'absorbed' by the load and the lines and transformers in the area of concern by an 'adequate' margin (also called the reserves). The 'margin' computation is made for a variety of contingencies. The difficulty is in exactly computing what the 'reserves' should be and what the static and dynamic parts should be that will be 'adequate' for various operating conditions. The split between the required Dynamic and Static MVARs has to be computed on a case by case basis for critical areas. Several empirical methods exist to determine this split, but have proved inadequate during post-mortem studies of blackouts.

There are analytical methods and tools to determine reactive power MVAR reserves. Static methods use computations that provide MW Power-Voltage and MVAR-Voltage curves (also known as PV and QV curves). Dynamic methods use stability programs with special provisions for long runs (minutes rather than seconds). These VAR Standards *do not even mention dynamic and static VARS* or these analytical tools.

Locational Decisions and Identifying Potential Voltage Instability Areas

MW power is transmitted from generators to loads through the transmission network. The network voltages must be maintained by MVAR supply for power to flow. As loads increase, flows through the lines increase, voltages decrease and MW and MVAR losses increase. This gets worse as key lines or generators trip in the general area. (When this gets into an uncontrollable repetitive cycle, we have 'voltage instability' as voltages collapse). To support voltage in an area, the reactive power is best supplied close to where the system voltage sags are the greatest, or where a reactive power 'deficiency' has been identified. Transmission Operators should be required by the standards to identify all potential voltage instability areas, determine the critical buses and the potential contingencies that could lead to voltage instability. This may not cover all conditions but will narrow the list to critical ones. Operating instructions should identify optimum location(s) and the amount of MVAR needed to maintain voltages for a variety of contingencies and operating conditions.

It should be noted that the power system is a continually growing dynamic system in terms of loads, and generators. Many areas have experienced problems as generators retire and are not replaced by new generation, or are replaced by cheap, remotely located generation supply.

Planning Vs Operation Scenarios

In the planning standards similarly, it should be required to identify all potential voltage instability areas and the optimum location(s) and the amount of MVAR needed to maintain voltages for a variety of contingencies and operating conditions. The answers may be quite different in

Commenter	Reliability Need	Acceptable Translation	Comments

planning studies which may show adequate MVAR reserves in generators. But in a real-time operation situation where generators are bid into the market on a MW basis only, the numbers may be quite different. The MVAR 'capability' may well exist in remote generators, but this is different from the actual 'local capability' that is required as system conditions get worse.

Voltage Control Schedules are Usually Prepared Ahead of Time– How Applicable are they in Real-Time?

Questions arise on how good is the Voltage Schedule as it relates to real-time if it is prepared ahead of time. Wouldn't the system conditions dictate what the schedule is in real-time? How will a-100 generators be notified to change their voltage settings if suddenly severe contingencies occur that upsets planned schedules?

Voltage schedules relate to operation practices and are set by operation-planning studies that result in a 'voltage profile' that should be maintained. These schedules generally follow the general directions of flow from generation 'areas' to load 'areas'. (For e.g. in WECC, the Northwest would have voltages at 110% and the southern buses in California would have voltages close to 100 %.) The Interconnection however is comprised of many control areas which may have different policies in maintaining its required 'voltage profile. Standards should require that they coordinate with other control areas or regions because in real-time, physics ignores man-made borders. Blackout investigations often show that conditions outside sometimes influence the outcome inside the area. Real-time operation has additional road blocks as seams issues make it impossible to view conditions outside the control areas. Standards should encourage a wider view of the system and the possibility of sharing data across systems.

Generator AVRs required to maintain a specified voltage setting

Ensuring a required set-point voltage on generator AVRs is the best way to ensure that voltages will be maintained at the generators – and hence at the EHV bus. Operation during emergency conditions should be specified. Automatic over-excitation and under-excitation limiters in generator AVRs ensure that MVAR limits are not exceeded during operation. The practice of power factor control must be discontinued for generators which must be under continuous automatic voltage control.

The primary function of the generator AVR (Automatic Voltage Regulator) is to regulate generator voltage for the exciter to supply MVARs. Other features available in AVRs allow for 'reactive current compensation' or regulation that takes into account the generator-transformer impedance, or to allow MVAR sharing of many generators in the plant. 'Joint control' of many generators can set the voltage at the HV side as the reference, but will ensure that each unit provides MVARs in proportion to its capability curve.

Difficulties to the Operator in Recognizing Impending Voltage Collapse

Studies of the 1996 blackouts in the Western Interconnection showed that the MVARs supply from the system shunt caps fell off rapidly towards the end, and generators were not able to supply required MVARs made worse by generator tripping in critical areas. Operators had difficulty in recognizing that a collapse was imminent on July 2, 1996 from observing the voltages on their voltmeters because recordings showed that the voltages held up well until the last 30 seconds. Holding up voltages till the last is a characteristic of shunt capacitors. The quantity of MVARs supplied by shunt capacitors is directly proportional to the square of the voltage, hence as the voltage plunges, so does the effectiveness of shunt capacitors. In general, the effect of non-availability of reactive power is non-linear in nature as seen in MW Power-Voltage and MVAR-Voltage (PV and QV) curves and is difficult to predict.

The conclusion is that standards should not emphasize only adequate voltage profiles as a requirement without mentioning the very necessary dynamic reactive power to avoid voltage collapse and a measurement to its adequacy.

Difficulty in Real-Time Measurement of 'Adequate' Reactive Reserves.

If the static PV-QV calculations state that there should be for e.g. 500 MVARs of reserves at a specific 500 kV bus, the difficulty is to measure it

Commenter	Reliability Need	Acceptable Translation	Comments

practically whether such an ‘adequate’ reserve is actually available at that bus.

Measurement is therefore practically related currently to whether generators plus capacitors plus SVDs in an ‘area’ cumulatively have adequate MVAR reserves. The area will need to be ‘bounded’ for such a definition to work.

The conclusion is that a ‘theoretical’ calculation is possible, but a practical measurement or quantification of ‘adequate’ reserves in real-time *at a bus* is impractical. The best approach that the industry has at present is to calculate in real-time through state-estimated solutions and ensure ‘adequate’ reactive reserves are available in operation for critical areas during emergencies.

An Important Topic not touched upon in the NERC Standards – Reliability and Optimal System Operation

The Security Constrained Optimal Power Flow (SCOPF) program is the best tool there is today that integrates economics, generation dispatch and transmission power flows considering the reactive power and voltage constraints of the system. Unfortunately, currently most ISO market systems, except for the NYISO (and a future CAISO), that run LMPs (Locational Marginal Prices), use only DC SCOPF Programs in dispatching generators that do not consider reactive power and voltage constraints of the system. DC SCOPF programs assume that voltages are equal to 1.00 pu at all buses. Hence units will always be dispatched optimally for MW only. This is understandable because the market currently focuses on MW and not MVAR.

It is therefore very advantageous that AC Security Constrained Optimal Power Flow (SCOPF) Programs be used instead of DC SCOPF programs by Market Systems in dispatching generators in order to include reactive power and voltage constraints of the system.

Whether the new Standards should recognize these issues in market systems and make it possible to integrate optimal dispatch of MW and voltage control/reactive power dispatch of MVARS will be likely opposed strongly by those who use DC OPF programs. But this is an opportunity to get things right and efforts should be made in that direction.

Conclusions and Recommendations

A new SAR is required to address the many points raised in these comments. It is clear that the VAR series of NERC Standards: VAR-001-1, VAR-002-1, VAR-003-1 on Voltage and Reactive Control, Generation Operation and Planning Assessment do not address the critical and practical requirements of voltage control and reactive power under emergency conditions.

These standards must address voltage instability, arguably the most difficult phenomena in systems operation today. These important NERC Standards to ensure that system reactive resources are “adequate” or “sufficient” to plan and operate the system so that voltage stability is ensured should therefore not have imprecise or vague requirements.

Response: Thank you for your comment. The DT supports the submission of a SAR as described in your conclusions and recommendations.

Comments on Field Test and Effective Date

There were no comments suggesting field testing this standard or suggesting alternate effective dates.

Commenter	Reliability Need	Acceptable Translation	Comments

VAR-002-1 Generator Operation for Maintaining Network Voltage Schedules

Commenter	Reliability Need	Acceptable Translation	Comments
Barry Green – Ontario Power Generation			(From Q 4 – Other comments) The definition of the levels of non-compliance are based on the accumulated numbers of "unithours" of operation out of compliance. Such a measure does not take account of the fact that not all units are equally impactive. Being out of compliance for a small hydroelectric unit is not equivalent, in terms of system impact, to being out of compliance for a large fossil or nuclear station.
Response: VAR-001 requires the TOP to identify generating units that are exempt from following voltage and reactive schedules, and this is expected to include very small units.			
Greg Mason – Dynergy Generation			(From Q 4 – Other comments) Requirement R1.1 of VAR-002-1 seems redundant to Requirement R14 of TOP-002-0.Suggest deleting R1.1 from VAR-002-01.
Response: The drafting agrees the language is redundant and is recommending that R14 of TOP-002 be modified to eliminate the duplication - VAR-002-1 is more comprehensive and requirements should only reside in one standard.			
Les Pereira P.E.			Please see VAR-001-1
Response: Please see response to VAR-001-1			
Kansas City Power and Light	Yes	No	It appears this standard is redundant with TOP-002, TOP-003, IRO-005
Response: The drafting agrees the language is redundant and is recommending that R14 of TOP-002 be modified to eliminate the duplication - VAR-002-1 is more comprehensive and requirements should only reside in one standard. The drafting team does not find redundancies with TOP-003 which includes requirements for coordination of outages or IRO-005 which addresses the RC's requirements for monitoring and directing control of its RC Area to stay within defined limits. There are requirements in IRO-005 for the RC to direct the GOP to make operating changes to return to within defined limits, but there are no requirements in IRO-005 for the Generator Operator.			
Deborah M. Linke	Yes	No	We agree the generation owner will maintain the voltage schedule provided by the

Commenter	Reliability Need	Acceptable Translation	Comments
– US Bureau of Reclamation Rebecca Berdahll – Bonneville Power Administration Karl Bryan – Corp of Engineers Jay Sietz – US Bureau of Reclamation Brenda Anderson	Yes	No	transmision operator within the capability of the generator; however in practicality the transmission operator monitors the voltage levels with the appropriate instrumentation (that may not even be available to the generator owner). As such they are the logical entity to log instances in which a voltage schedule was not met. The standard does not define what voltage level constitutes a deviation from the schedule, +/- 1% ?
Response: The drafting team removed the logging requirements from this standard. The GOP must have evidence it complied with the requirements, and logging is just one of the methods that may be used as evidence of compliance. Any deviation beyond the schedule (plus or minus any range or bandwidth) is a deviation from schedule.			
Kenneth Dresner – FirstEnergy Solutions		No	The standard is well written but the 5 day time frame to respond to R5 is to short The number of transformers can amount to the hundreds and a response time of 30 business days seems more appropriate. Also the definition of Auxiliary transformer needs to be clear. I believe that by merging of the standards will make the tracking of compliance more difficult. The issue of being noncompliant on one Requirement will roll up to the noncompliance to the overall standard This will make physically tracking the compliance levels more difficult
Response: VAR-002 R5 was revised and now states the GOW has 30 calendar days to provide a response. The Generator Owner is expected to have the information already compiled – the 30 days is intended to give the GOW time to gather the already documented information. The draft standard was modified as follows to identify more specifically the subset of auxiliary transformers that are addressed in requirement R5: – auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage. Eventually, measures and non-compliance will be added to all the requirements from Version 0. The drafting team will ask stakeholders if they			

Commenter	Reliability Need	Acceptable Translation	Comments
prefer to have the Phase III & IV measures moved to separate standards.			
Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	Would like the vebiage to read either Generator Owner or Transmission Owner to supply this information. In our company, the Transmission Operator keeps the official records. B. R1. R1.1 and R1.2 We concur these R9.1 and R9.2 should be moved to VAR-002. B. R1. R1.2 Proposed adding "automatic" between Generator's and voltage. R4 &R5:Does this include load as well as non-load tap changers. Is this referring to older voltage regulator systems (load tap changers) that may just change taps to control the generator voltage? D.2. 2.4.2 The non-compliance for not changing the tap (settings) as requested should also include not changing the generator voltage to maintain the system voltage (R2). This is the main intent of this Standard.
Response: The requirement to log information was removed from the standard. The GOW was assigned responsibility for providing the information about the unit – according to the Functional Model, the GOW should provide this data. The GOW may choose to delegate this task to another entity. Most commenters agreed with moving R9.1 and R9.2 to VAR-002 and the drafting team made this modification. The word, 'automatic' was added as suggested. The revised standard is more specific about which tap changers are addressed in Requirements 4 and 5. All four levels of non-compliance for the Generator Operator include sanctions for operating off the voltage or reactive power schedule or operation without automatic voltage control for various time periods. The revised standard includes separate levels of non-compliance for the Generator Owner – these levels of non-compliance assign sanctions for failing to provide data or for failing to ensure that tap settings are made in accordance with the documentation provided by the TOP.			
Greg Mason – Dynergy Generation	Yes	No	1. In Sections B,R1.1 and BR3 what is the basis for 30 minutes? A specific timeframe is not in the current standard. Suggest using the wording from TOP-002-0 which provides for notification "without any intentional time delay. "If this requirement is retained, this timeframe is unrealistic given the multiple parties to be notified (i.e. Control Center, Reliability Coordinator, etc.) and the specific reference to time should be lengthened to 60 minutes. 2. In Section B,R3 this reporting requirement only makes practical sense if the voltage schedule is a range since you would deviate from a specified voltage virtually all the time. Suggest clarifying that the requirement relates to a "scheduled voltage range that takes into

<table>
<tr><th>Commenter</th><th>Reliability Need</th><th>Acceptable Translation</th><th>Comments</th></tr>
<tr><td></td><td></td><td></td><td>account voltage measuring accuracy and the dynamics of system voltage" and eliminate the reference to a reactive schedule.

3. Levels 2,3 and 4 of Non-Compliance are overly severe and should be reevaluated. Suggest tying Level 4 non compliance to 48 hours instead of 24 hours. Also, the wording regarding "time off" the voltage schedule needs to better defined(i.e. instantaneous vs. integrated)</td></tr>
<tr><td colspan="4">Response: The drafting team modified the standard to include the following statement, which should address your concern about the 30 minute notification period:

If unable to notify the Transmission Operator within 30 minutes, the Generator Operator shall have documentation to support the reasons for not making the notification within 30 minutes.

Either a specific voltage with tolerances or a voltage range can be used for a voltage schedule.

There were very few suggestions indicating the levels of non-compliance were inappropriate, so these weren't changed as suggested.</td></tr>
<tr><td>NERC Interconnection Dynamics Working Group</td><td>Yes</td><td>No</td><td>Purpose: Replace (within limits in real time) with (within and up to equipment capabilities).

R1.1 – change (status of each voltage regulator) to (status of automatic voltage regulator).

R4 – Specify GSU and major auxiliary transformers connected to the generator bus.

Modify in R1… regulator in service in voltage control mode, not power factor control mode</td></tr>
<tr><td colspan="4">Response: The drafting team has modified the purpose to use the phrase, 'within applicable Facility Ratings' in support of your suggestion.

R1.1 (Now R3.1) was modified to qualifier 'automatic' as suggested.

R1 was not modified as suggested because the suggestion is in conflict with allowing generators to operate to a reactive schedule as described in VAR-001-1.</td></tr>
<tr><td>Resource Issues Subcommittee</td><td>Yes</td><td>No</td><td>1. The 30 minute notification period of R3 may be too short for some small or remote generators. Suggest adding a clause "or other period agreed to by the TO".

2. R3 should be redrafted to make clear what is being required. R3 could be interpreted to mean that the GO is required to report to its TO within 30 minutes from the time that the TO requests a report, as opposed to 30 minutes after the GO cannot maintain a voltage schedule.

3. The accumulation of 8, 16, and 24 unit-hours used to determine Levels of Non-Compliance do not specify the time period over which they accumulate.

4. What is the basis for the unit-hour breakpoints in the Compliance Section and are they</td></tr>
</table>

Commenter	Reliability Need	Acceptable Translation	Comments
			reasonable across the various regions of NERC? 5. Exemptions to R1 should be allowed for planned startup and shutdowns. 6. Recommend striking reference to auxiliary transformers from all sections of the standard. 7. Add to R4 - Prior to agreeing to changes in the main step-up transformer tap settings, the Generator Operator shall consider and plan for changes to those settings and adjust auxiliary systems as necessary. 8. Please clarify that R3 does not require the GO to monitor grid voltage every 30 minutes. The GO should monitor its adherence to the TO's voltage schedule.

Response:

The drafting team modified the standard to include the following statement, which should address your concern about the 30 minute notification period:

> If unable to notify the Transmission Operator within 30 minutes, the Generator Operator shall have documentation to support the reasons for not making the notification within 30 minutes.

R3 was revised and states, ' R3.Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of any of the following:'

The performance reset timeframe is one calendar year per section D.1.2. The reset timeframe is the time period, over which the performance is measured, evaluated and then reset.

The unit-hour timeframes was a carryover from the original planning documents. Industry stakeholders must comment to let us know if these timeframes are appropriate.

The drafting team believes this issue is covered in R1- refer to the word "connected". (R1. The Generator Operator shall operate each synchronous generating unit connected to the interconnected transmission system in the automatic voltage control mode. . .)

The standard was modified so that the only reference to auxiliary transformers is in the requirement for the Generator Owner to provide information about its equipment to the TOP and the TP – the revised requirement states that the GO must provide information: For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

The suggested modification to R4 is a routine activity for the Generator Operator and isn't necessary in the standard.

The 30 minutes in R3 is the timeframe the Generator Operator has to notify the TOP of the status change.

Commenter	Reliability Need	Acceptable Translation	Comments
Southern Company –	Yes	No	R1.3 - Add the qualifier -upon request-.

Commenter	Reliability Need	Acceptable Translation	Comments
Transmission			Recommend revising to say, -Upon request, each Generator Operator shall report to its Transmission Operator the date, time, duration, and reason for each period when a voltage or reactive schedule for a generator was not maintained. The Generator Operator shall maintain a written log of this information for 12 rolling months.- R5 - Strike the words -and auxiliary-. There is no transmission reliability need for generators to provide the auxiliary transformer information to the specified entities. After ….and NERC,….add the words -prior to equipment changes and- …… Five (5) business days is not reasonable and should be increased to 14 calendar days.
Response: R1.3 was revised to simply require the GOP to notify the TOP within 30 minutes of a change in status on any synchronous generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer. This ensures the TOP has the information needed to make operating decisions. The requirement to log this information was dropped from the standard since it does not add appreciably to reliability. The standard was modified so that the only reference to auxiliary transformers is in the requirement for the Generator Owner to provide information about its equipment to the TOP and the TP – the revised requirement states that the GO must provide information: For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage: The drafting team believes the suggested wording change to R5. is not necessary as it is covered in the MOD-010 and MOD-011 standards. The time for providing the information was changed from five business days to 30 calendar days.			
Southern Company Generation	Yes	No	R1.3 - Add the qualifier "upon request". R3 - The requirement for the Generator Operator to monitor grid voltage every 30 minutes is a new and unnecessary burden on the plant operator. Also, the log is only needed when the Transmission Operator does not approve present voltage or reactive output. R3 is needed only to address the documentation for cases when the plant operator cannot meet R2. Recommend revising R3 to say, "Each Generator Operator shall maintain a written log of the date, time, duration, and reason for each period when a voltage and reactive schedule for a generator was not maintained as specified by the Transmission Operator. This log shall be maintained for 12 rolling months." This will minimize paperwork, because it will result in a log entry only when either the plant operator cannot meet the transmission operator's requirement or does not get the transmission operator's concurrence." R5 - Strike the words "and auxiliary". There is no transmission reliability need for generators to provide the auxiliary transformer information to the specified entities.

Commenter	Reliability Need	Acceptable Translation	Comments
			This should be removed here and included in the Nuclear Offsite Power Reliability Standard. Five (5) business days is not reasonable and should be increased to 14 calendar days.
Response: R1.3 was revised to simply require the GOP to notify the TOP within 30 minutes of a change in status on any synchronous generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer. This ensures the TOP has the information needed to make operating decisions. The requirement to log information was dropped from the standard since it does not add appreciably to reliability. The 30 minutes in R3 is the timeframe the Generator Operator has to notify the TOP of the status change. The standard was modified so that the only reference to auxiliary transformers is in the requirement for the Generator Owner to provide information about its equipment to the TOP and the TP – the revised requirement states that the GO must provide information: For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage: Please submit your suggestion for an additional requirement in the nuclear SAR to the Nuclear SAR Drafting Team the next time that SAR is posted for comment. The drafting team changed five business days to 30 calendar days.			
Constellation Generation Group	Yes	No	In R2, a operational range that is not harmful to the generator needs to establish and recognized by the transmission operator before a generation operator can required to be instructed to maintain a synchronous voltage or reactive output level by the transmission operator.
Response: The companion standard, VAR-001, was modified to include the following requirement: R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule to be maintained by each synchronous generator, within applicable Facility Ratings, at a specified bus and shall provide this information to the Generator Operator. clarify that the voltage or reactive schedule			
Tennessee Valley Authority SERC EC Generation Subcommittee (GS) Jerry Nicely –	Yes Yes Yes	No No No	Exemptions should be allowed for planned startup and shutdowns (R1) Strike the words and auxiliary from all sections of the standard. Add to R4 - Prior to agreeing to changes in the main step-up transformer, the Generator Operator shall consider and plan for changes to those settings and adjust auxiliary systems as necessary. The requirement for the GO to monitor grid voltage every 30 minutes is a new and

Commenter	Reliability Need	Acceptable Translation	Comments
TVA Nuclear Generation D. Bryan Guy – Progress Energy, Inc.			unnecessary burden on the plant operator.
Response: The drafting team believes this issue is covered in R1- refer to the word “connected”. (R1. The Generator Operator shall operate each synchronous generating unit connected to the interconnected transmission system in the automatic voltage control mode. . .) The standard was modified so that the only reference to auxiliary transformers is in the requirement for the Generator Owner to provide information about its equipment to the TOP and the TP – the revised requirement states that the GO must provide information: For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage: The suggested modification to R4 is a routine activity for the Generator Operator and isn’t necessary in the standard. The 30 minutes in R3 is the timeframe the Generator Operator has to notify the TOP of the status change.			
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	No	Is it the intent of requirement R5 that a request by any one of the three entities will require the Generator Operator provide the data to that entity or all three? In the past communication of data between the Generator Operator and the Transmission Operator was routine and at such times no parallel path was established with the Regional Reliability Organization or NERC. To prevent a violation must all such information be distributed at the same time to all three entities?
Response: The requirement was modified so the Generator Operator only needs to provide the information to the TOP or the TP, whichever one requests the data. Note that the timeframe for responding to this request was lengthened to 30 calendar days.			
SPP Transmission Working Group	Yes	No	No timeline for voltage schedules. R12 – no standard for NERC Votage Stability Analysis in associated limits.
Response: Agree. The standard does not include a requirement for a timeline for voltage schedules, however the standard does not preclude the use of a timeline and this standard does not require a voltage stability analysis. Adding these elements would be an expansion of the scope of the Phase III & IV SARs.			
Mark Kuras – MAAC	Yes	No	Level of non-compliance 2.4.2 seems to imply that the TO can order the GO to make changes to their GSU tap. I thought it had to be an agreed upon change (See R4). Also this is not

Commenter	Reliability Need	Acceptable Translation	Comments
			mentioned in the measures.
Response: The requirements, measures and associated levels of non-compliance were all modified. The revised requirement for making changes to transformer tap settings uses the phrase, 'after consultation with the TOP.' The revised standard does have a measure that indicates the GO must have evidence its step-up transformer was changed per the TOP's documentation.			
Individual Members of CCMC Joseph D Willson – PJM	Yes Yes	No No	Levels of non-compliance are adding requirements. The 8, 16, 24 hours must be removed. Requirements must be modified. Remove "within 30 days". This standard seems to have very similar requirements and levels of non-compliance as VAR-001. Either eliminate the redundancy (ex. Time unit was not operating with automatic voltage regular (control) in service) between the two or combine the standards.
Response: The drafting team notes the time frames mentioned in the non-compliance section existed in the original document. The drafting team does not have sufficient information to respond to your comment regarding modifying requirements. The requirements, measures and associated levels of non-compliance were all modified. The revised measures do not include reference to 'within 30 days'. The drafting team made many modifications to both VAR-001 and VAR-002 and eliminated the redundancy. VAR-001 no longer requires the TOP to develop and distribute to the GO/GOP procedures that require the GO/GOP to adhere to VAR-002.			
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Dominion Electric Transmission agrees with moving VAR-001 R9.1 and R9.2 to VAR-002, as R1.1 and R1.2.
Response: Thank you for your comment. We have made the changes based on industry support.			
Doug Hohbough – First Energy Corp.	Yes	Yes	Proposed move of sections to VAR-002-1 is ok.
Response: Thank you for your comment. We have made the changes based on industry support			

Commenter	Reliability Need	Acceptable Translation	Comments
John Horakh – MACC	Yes	Yes	OK to move R9.1 and R9.2 to VAR-002.
Response: Thank you for your comment. We have made the changes based on industry support			
PPL Corporation	Yes	Yes	PPL believes that a NERC standard should require all Generator Owners to have their Automatic Voltage Regulators (AVRs) in service and to immediately report any AVR outages to the system operator.
Response: The standard was revised to require GOPs to report to the TOP any time there is a status change to an AVR.			
Michael C. Calimano – NYISO	Yes	Yes	The generators that are required to operate and report should be limited to those that are greater than 20 MWs or connected at 100KV and higher. NYISO recommends to remove "synchronous" throughout VAR-002-1.
Response: The TOP is required (in VAR-001) to identify generating units that don't need to follow a voltage or reactive power schedule. Induction generators generally cannot provide VAR support so the drafting team did not remove the word, 'synchronous'.			
Consolidated Edison NPCC CP9 RSWG Kathleen Goodman – ISO-NE IESO – Ontario Vinod Kotecha Alan Adamson – NYSRC Ed Riley – California ISO	Yes Yes Yes Yes Yes Yes Yes	Yes Yes Yes Yes Yes Yes Yes	The generators that are required to operate and report should be limited to those that are considered to be part of the Bulk Electric System.

Commenter	Reliability Need	Acceptable Translation	Comments
ISO/RTO Council Standards Review Committee			
Response: The TOP is required (in VAR-001) to identify generating units that don't need to follow a voltage or reactive power schedule.			
Transmission Issues Subcommittee	Yes		Remove reference to "synchronous" throughout the standard. Clarify that R1 applies to all generators capable of automatic mode AVR operation. The translation table refers to R6, which is not in this standard.
Response: Induction generators generally cannot provide VAR support so the drafting team did not remove the word, 'synchronous'. The TOP is required (in VAR-001) to identify generating units that don't need to follow a voltage or reactive power schedule. This was a typographical error and has been removed.			
Barry Green – Ontario Power Generation	Yes		R1.1 - There are some generating units that by virtue of their location and/or size have diminimus impact on transmission system limits. The standard should have provision for exclusion from this requirement for such units. R1.2 - The purpose of R1.2 is unclear. The AVR is used to respond to transient conditions, not to meet schedules as instructed by a Transmission Operator or Reliability Authority. Meeting such schedules is done by operator manual adjustments, whether the AVR is in service or not. R2 - A Generator Obligation to "maintain" generator voltage or reactive output could be problematic. During transient conditions, attempting to maintain reactive output at a level specified under steady-state conditions could exacerbate a problem. R5 - The term "auxiliary transformers" should be defined to refer only to those transformers connected directly to the transmission system. R5 - The obligations included here in are not included in Existing Standards M2, M4 or M6. Either there is another standard that is being superceded by these standards which should be listed or this requirement should be moved to an alternative standard. Levels of Non-Compliance:

Commenter	Reliability Need	Acceptable Translation	Comments
			See additional comments in response to question 4
Response: The TOP is required (in VAR-001) to identify generating units that don't need to follow a voltage or reactive power schedule. -002. R1.2: AVR response is taken into consideration in determining voltage schedule, as the AVR will maintain the voltage schedule. In the event of AVR failure the transmission operator may direct the Generator Operator to a new voltage schedule to compensate for the loss of the transient response of the excitation system; no change is needed. The standard was modified so that the only reference to auxiliary transformers is in the requirement for the Generator Owner to provide information about its equipment to the TOP and the TP – the revised requirement states that the GO must provide information: For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage: The obligations included in this standard are interpretations from planning standards IIIC M2, M4, M6;			
Transmission Subcommittee			VAR-002-1, R2, TS suggests the last part of R2 is assumed to be within the proposed R2 language and recommends the R2 language be modified as follows: Each Generator Operator shall maintain the synchronous generator voltage or reactive output "within the reactive capability of the unit as "specified (delete)" "directed (add)" by the Transmission Operator. "unless otherwise approved by the Transmission Operator. (Delete)." VAR-002-1, R3, TS recommends referencing "within 30 minutes" be anchored to a start time, end lime, or another reference point. By itself, the "within 30 minutes" is ambiguous. TS Consideration: The TS is concerned that this standard may not be the most optimal location for "documentation and reporting" requirements. If the reporting criteria is contained within a "Documentation and Reporting" standard, then the respective requirements should be deleted from this standard. (example: VAR-002-1, R3) VAR-002-1, M2, TS Recommendation: M2 lacks a "within X amount of time" that other measures contain. To be consistent with other standards, a reporting window should be included.
Response: The language in R2 was changed to use the word, 'directed' rather than, 'approved' and the extra phrase, 'unless otherwise approved by the Transmission Operator' was dropped as suggested. The requirements to notify the TOP were grouped together as follows: Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of any of the following: The requirements to log actions were removed from the standard because they don't add appreciably to reliability. Logs may be used as a type			

Commenter	Reliability Need	Acceptable Translation	Comments
of evidence supplied by the GOP to show compliance, but logging is not specifically required in the revised standard. The requirement associated with M2 from the 1st draft of this standard required logging – and that requirement and associated measure have been removed from the revised standard.			
Midwest Reliability Organization	Yes	Yes	Move VAR-001 R9.1 and R9.2 to VAR-002 R1.1 so that all Generator Owner requirements are together. R1.3 Should the standard allow for an exemption for smaller units? R3. Reference necessary in this standard to TOP-002-0 R14.
Response: The drafting team did move VAR-001 R9.1 and R9.2 as suggested. The TOP is required (in VAR-001) to identify generating units that don't need to follow voltage or reactive power schedules. The drafting agrees the language is redundant and is recommending that R14 of TOP-002 be modified to eliminate the duplication - VAR-002-1 is more comprehensive and requirements should only reside in one standard.			
Raj Rana – AEP	Yes	Yes	Reword R4 as follows: When mutually agreed with the Transmission Operator, the Generator Operator shall change transformer tap positions… upon time frame.
Response: R4 was reworded to support the intent of this suggestion.			
Peter Burke – American Transmission Co.	Yes	Yes	Move VAR-001 R9.1 and R9.2 to VAR-002 so that all generator owner requirements are together. Revise M3 to contain "available upon request"
Response: The drafting team did move VAR-001 R9.1 and R9.2 as suggested. The associated requirement was modified so that the GO must provide this information to its TOP and TP within 30 calendar days of a request – the revised measure states that the GO must have evidence the information was provided as required.			
Entergy	Yes	Yes	
Karl Kohlrus - City Water,	Yes	Yes	

Commenter	Reliability Need	Acceptable Translation	Comments
Light & Power			
Ronnie Frizzell - Arkansas Electric Coop. Corp.	Yes	Yes	
Howard Rulf - WE Energies	Yes	yes	
Joseph F. Buch – Madison Gas and Electric	Yes		
Samuel W. Leach – TXU Power	Yes	Yes	
Xcel Energy – Northern States Power	Yes	Yes	
SERC EC Planning Standards Subcommittee (PSS)	Yes	Yes	
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Gerald Rheault – Manitoba Hydro	Yes	Yes	

Commenter	Reliability Need	Acceptable Translation	Comments
WECC Reliability Subcommittee	Yes	Yes	
Mohan Kondragunta – Southern California Edison	Yes	Yes	

Members	Field Test Required?	Recommended Date?	Justification

Comments on Field Test and Effective Date

Summary Consideration: Most commenters did not indicate a need for field testing and the drafting team is not recommending field testing of this standard. This standard needs to be implemented at the same time as VAR-001 – and entities need time to meet the new requirements in VAR-001. The drafting team is recommending that VAR-001 and VAR-002 both become effective January 1, 2007.

Midwest Reliability Organization	Yes		Previous regional requirements allowed for exemptions for smaller generators. Will require some external evaluation and additional costs.
Response: VAR-002 doesn't reference any regional requirements that would exempt generators from compliance with this standard.			

Commenter	Reliability Need	Acceptable Translation	Comments

VAR-003-1 Assessment of Reactive Power Resources

Les Pereira P.E.			Please see VAR-001-1

Response: Please see VAR-001-1 response.

Carson Taylor – Bonneville Power Administration			Static and dynamic reactive power must be carefully defined. Preferably, better terms should be used. "Static" usually is taken to mean fixed or mechanically switched capacitor/reactor banks, and that mechanical switching is operator-directed in a slow time frame (basically fixed). At BPA and at other companies capacitor/reactor banks are rapidly switched following disturbances by local voltage relays, SPS/RAS, or within a few minutes via SCADA operators. Fraction of a second switching is used by both voltage relays and SPS/RAS. During the June 14, 2004 loss of 4600 MW of Arizona generation event, BPA shunt and series capacitor banks and shunt reactors switched during the first forward angle swing by voltage relays and RAS. Operators switched other banks within two minutes as voltage again decayed because of Northwest governor action. A circuit breaker is pretty dynamic. The problem that shunt capacitor bank output is a function of voltage-squared is dealt with in design by the control settings, bank sizes, and number of banks so that the voltage is not allowed to collapse. The word "static" is used in "static var compensator" to mean power electronic rather than mechanical switching. "Continuous automatic control" and "discontinuous automatic control" might be better terms. Better yet, why not a simple statement that various types of reactive power resources at effective locations must be planned and operated to meet performance requirements?

Response: The terms static and dynamic reactive power resources are much more familiar industry-wide; no change was made to the standard.

Tennessee Valley Authority	Yes	No	TVA agrees that there is a reliability need, but it feels that the intent of this standards is already covered in TPL-001 thru 004

Response: TPL-001 through TPL-004 present a wide area view whereas VAR-003 focuses more narrowly on reactive resources.

Commenter	Reliability Need	Acceptable Translation	Comments
Kansas City Power and Light	Yes	No	It appears this standard is redundant with other standards

Response: Please be more specific by identifying the redundancies.

Gerald Rheault – Manitoba Hydro	No	Yes	The adequacy of reactive power resources is verified by system assessments in TPL-001 to 004. Meeting the performance requirements implies adequate resources. This standard is redundant. A standard defining a minimum reactive reserve requirement may be more meaningful.

Response: TPL-001 through TPL-004 present a wide area view whereas VAR-003 focuses more narrowly on reactive resources.

Developing a standard for a reactive reserve requirement wouldn't be within the scope of the SARs for the Phase III & IV Measures.

Midwest Reliability Organization	No	No	Merge requirements in R1 of VAR-003-1 into TPL-001-0, TPL-002-0, and TPL-003-0 with requirement in Measures of the TPL standards for review and assessment once every five years. R2 has the same intent as R1.3.9 in the TPL standards. R3 is identical to R3 of the TPL standards. VAR-003 can now be eliminated.

Response: TPL-001 through TPL-004 present a wide area view whereas VAR-003 focuses more narrowly on reactive resources; merging the requirements into TPL-001 through TPL-004 will lose that focus

Greg Ludwicki – Northern Indiana Public Service Co.	Yes	No	I interpret requirement for an annual test. Recommend a longer time frame unless operational anomalies are encountered, possibly 5 years.

Response: The standard requires the assessment to be performed every five years or as required by changes in the system conditions.

SPP Transmission Working Group	Yes	No	Requirement for developing a methodology and criteria for the assessment reactive resources should be done on a regional basis and therefore should be the responsibility of RRO.
Ronnie Frizzell - Arkansas	Yes	No	

Commenter	Reliability Need	Acceptable Translation	Comments
Electric Coop. Corp.			

Response: Reactive resources need to be addressed at the local level, not the regional level.

Commenter	Reliability Need	Acceptable Translation	Comments
John Horakh – MACC	Yes	No	The need to have a balance between static and dynamic reactive power resources is stated in the Purpose. The need should also be explicitly stated in the measures.

Response: The purpose statement was revised so that the original language, '…with a balance between static and dynamic characteristics…' was replaced with, '…considering static and dynamic characteristics…'

Commenter	Reliability Need	Acceptable Translation	Comments
FRCC	Yes	No	Delete R1 – Since the methods and criteria are Region and area specific, this requirement cannot be used to determine if the "correct" methods and criteria are being applied. The reactive assessment should be comprehensive and should not be limited in scope by methods and criteria that were previously adopted. As the system changes over time, with load growth and new facilities, any methods and criteria may need to be changed in order to correctly assess the correct balance between static and dynamic reactive power requirements. R2 & R3 are adequate to ensure that the system has adequate reactive resources in the correct balance.

Response: The measures don't assess whether the method and criteria are 'correct' – just that they exist.

Commenter	Reliability Need	Acceptable Translation	Comments
Peter Burke – American Transmission Co.	Yes	No	R2.2 Suggest more frequent assessments, such as at least every three years M1 ...NERC within 30 calendar days... M2 Suggest assessment within the past three years D1.3 ...Compliance Monitor shall retain any audit data for at least five years. [three year is okay, if M2 is within the past three years] D2.2 What is the definition of an area? D2.3 R1 does not require review within the past five years D2.4 What is the definition of areas? Does this have to be a new stand-alone standard? It appears that the requirements lend themselves to be merged within TPL-001, TPL-002 and TPL-003.

Commenter	Reliability Need	Acceptable Translation	Comments

Response: The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

The first draft of the standard did intend to require that the documentation be produced within 30 calendar days of a request. The '3 days' was a typographical error.

M2 was modified to be consistent with the revised requirement which indicates an assessment must be done annually unless changes in system conditions do not warrant an annual assessment – but at least one assessment must be conducted every 5 years.

The intent of requiring the Compliance Monitor to have data is to ensure that if there is another system event that warrants widespread investigation (such as a blackout), Compliance Monitors will have evidence that all critical functions have been audited within the past 3 years and areas of non-compliance are being addressed. The Compliance Enforcement Program has every requirement audited at least once every 3 years, so keeping three years of data should be sufficient. The responsible entity must have its latest assessment available for the Compliance Monitor to review, so it isn't necessary for the Compliance Monitor's data retention to align with the periodicity of the assessments.

The levels of non-compliance were revised so the word, 'area' is no longer used.

The levels of non-compliance were revised so they align more closely with the revised requirements and measures.

The drafting team believes TPL-001 through TPL-004 presents a wide area view whereas VAR-003 focuses more narrowly on reactive resources; merging the requirements into TPL-001 through TPL-004 will lose that focus. The drafting team will ask stakeholders if they agree with keeping these requirements separate from the TPL standards.

Joseph D Willson – PJM	Yes	No	Level 2 and 4: who determines if the TP and/or PA assessment is incomplete in one area (since no areas are defined in the requirement.

Response: The levels of non-compliance were revised so the word, 'area' is no longer used.

Individual Members of CCMC	Yes	No	Level 2 and 4: Who determines if the TP and/or PA assessment is incomplete in one area (since no areas are defined in the requirement). This should probably be included in the TPL standards.

Response: The levels of non-compliance were revised so the word, 'area' is no longer used.

Mark Kuras – MAAC	Yes	No	Every requirement and measurement seems to imply that the TP and PA must redundantly do things. The …and… should be an …or… Level 3 non-compliance should be another sub-section of Level 4.

Response: The DT believes that the TP should do assessments for their individual areas and the PA should do assessments to make sure that

Commenter	Reliability Need	Acceptable Translation	Comments

there are no “seams” issues missed by the individual TP assessments. There should be no redundancy.

The levels of non-compliance were modified so that the failure to conduct an assessment is a level four as suggested. While the measure required the responsible entities to review their methodology every five years, there was no matching requirement to do so and this was dropped from the requirements, measures and levels of non-compliance.

Commenter	Reliability Need	Acceptable Translation	Comments
WECC Reliability Subcommittee	Yes	Yes	SCE supports this Standard. Existing WECC Standards address these requirements.
Mohan Kondragunta – Southern California Edison	Yes	Yes	

Response: Thank you for your comments.

Commenter	Reliability Need	Acceptable Translation	Comments
Alan Adamson – NYSRC	Yes	Yes	R2.2 should require that assessments be performed at least every two years, instead of every five years.

Response: The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

Commenter	Reliability Need	Acceptable Translation	Comments
Xcel Energy – Northern States Power	Yes	Yes	Requirement R2 - "shall acquire" is a financial term, not a guidance term. Recommend change to "shall maintain". Requirement R5.1 - "shall notify the Generator Operator of a voltage schedule or reactive output " is not clear. Recommend change to " the Transmission Operator shall direct the Generator Operator to either maintain or change its voltage schedule or reactive output as necessary" R2. Transfers involving designated network resources should also be included in theis requirement. M1. the timeframe should be 30 calendar days not 3.

Response: the DT is unable to find the term “shall acquire” in this standard.

There is no R5.1 in this standard

Commenter	Reliability Need	Acceptable Translation	Comments

If the transfers are “firm” then they are included. If they are not firm, then the DT believes it is appropriate to not consider them in this requirement.

The DT has modified M1 to reflect this comment. The ‘3’ was a typographical error.

Commenter	Reliability Need	Acceptable Translation	Comments
Transmission Subcommittee			VAR-003-1, R2.2., TS recommends rewording the R2.2. language as follows: The Transmission Planner and Planning Authority shall each perform this assessment at least once every "five (delete)" "three (add)" years or as required by "significant (add)" changes in system conditions "which may affect static and dynamic reactive power requirements. (add)" VAR-003-1, R2.2., TS Consideration: The term "changes in system conditions" is very liberal. TS recommends defining these changes as being significant to the assessment study (e.g. load growth, generation additions, dynamic and static reactive power additions or deletions, changes in operations, etc.). VAR-003-1, M1: TS believes that M1 requirement to provide evidence within "3 calendar days" is a typographical error and actually is "30 calendar days." TS believes 30 calendar days is a realistic time span for a request-documentation reporting window. VAR-003-1, M3: TS recommends an assessment every three years to coincide with recommended "three years" in R2, above.

Response: The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

The DT attempted to add a list of significant changes that may trigger the need for an assessment, but any list developed would not meet all circumstances, and the DT elected to refrain from including any list.

M1 did intend to say, ‘30’ rather than ‘3’ as suggested.

As noted above, the standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years. The measures need to align with the requirements.

Commenter	Reliability Need	Acceptable Translation	Comments
Consolidated Edison	Yes	Yes	R2.2 should require that assessments be performed at least every two years, instead of every five years.

Response: The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

Commenter	Reliability Need	Acceptable Translation	Comments
Transmission	Yes	Yes	R2.2 should state that assessments should be performed at least every two years, rather than

Commenter	Reliability Need	Acceptable Translation	Comments
Issues Subcommittee			five years. As approved by the NERC BOT, TIS recommends that Standard I.D guidelines G2 and G3 should be incorporated into this standard as follows: Distribution entities and customers directly connected to the transmission system should plan their respective systems to operate close to a specified power factor; and, at continuous rated power output, new generators should have an overexcited power factor capability, measured at the point of interconnection with the transmission system, of 0.95 or less and underexcited power factor of 0.95 or less. If a generator does not meet this requirement, the generation owner should make alternate arrangements (e.g. Statcoms, SVC, etc.) for supplying an equivalent dynamic reactive power capability to meet this requirement. (The drafting team should coordinate the generator power factor requirement with MOD-025-1.) M1 should refer to 30 calendar days, not 3.

Response: The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

Standards address requirements that are mandatory; guidelines are recommended practices. Adding guidelines to these standards is outside the scope of the standards process and is also outside the scope of the SARs for this Phase III & IV translation.

The typographical error in M1 was corrected to change '3' to '30'.

Commenter	Reliability Need	Acceptable Translation	Comments
John K. Loftis, Jr. – Dominion – Electric Transmission	Yes	Yes	Dominion Electric Transmission concurs with the addition of Planning Authorities to the list of applicable responsible parties and with including an additional requirement to develop a method and criteria for assessing adequacy of reactive power resources. Suggest that R2.1 be deleted. The requirements of R2.1 are included in R2.2. M1 should refer to 5 business days instead of 3 calendar days (typical Standards practice). The areas referred to D.2.2 and D.2.4.2 needs to be clarified.

Response: Thank you for your comment on the additional requirement for having a methodology and criteria for assessing adequacy of reactive power resources.

R2.1 is to cover planned future conditions as projected from the date of the assessment. (e.g., generator B retires in 2008). R2.2 is the trigger to re-perform the assessment (E.g., since the last assessment, load growth projections changed from 1% per year to 3% per year).

Commenter	Reliability Need	Acceptable Translation	Comments

The typographical error in M1 was corrected to change ‘3’ to ‘30’.

The levels of non-compliance were revised and the word, ‘areas’ is no longer used.

Commenter	Reliability Need	Acceptable Translation	Comments
Entergy	Yes	Yes	Suggest that R2.1 be deleted. The requirements of R2.1 are included in R2.2.
SERC EC Planning Standards Subcommittee (PSS)	Yes	Yes	M1 should refer to 5 business days instead of 3 calendar days (typical Standards practice). The "areas" referred to D.2.2 and D.2.4.2 needs to be clarified.

Response: The DT disagrees. R2.1 is to cover planned future conditions as projected from the date of the assessment. (e.g., generator B retires in 2008). R2.2 is the trigger to re-perform the assessment (E.g., since the last assessment, load growth projections changed from 1% per year to 3% per year).

The typographical error in M1 was corrected to change ‘3 calendar days’ to ’30 calendar days’.

The levels of non-compliance were revised and the word, ‘areas’ is no longer used.

Commenter	Reliability Need	Acceptable Translation	Comments
Vinod Kotecha	Yes	Yes	The M1 response time should be 30 days, not 3? R2.2 should require that assessments be performed every year. Regions should be allowed to continue present practices.

Response: The typographical error in M1 was corrected to change ‘3 calendar days’ to ’30 calendar days’.

The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

Regions may have separate requirements from NERC.

Commenter	Reliability Need	Acceptable Translation	Comments
IESO – Ontario	Yes	Yes	The M1 response time should be 30 days not 3
NPCC CP9 RSWG	Yes	Yes	
Kathleen Goodman – ISO-NE	Yes	Yes	
Ed Riley –			

Commenter	Reliability Need	Acceptable Translation	Comments
California ISO			
ISO/RTO Council Standards Review Committee			

Response: The typographical error in M1 was corrected to change '3 calendar days' to '30 calendar days'.

Commenter	Reliability Need	Acceptable Translation	Comments
Michael C. Calimano – NYISO	Yes	Yes	"Changes in system conditions" is vague and needs to be clarified. M3 assessment should be done every 3 years to coincide the R2 requirement.

Response: The DT attempted to add a list of significant changes that may trigger the need for an assessment, but any list developed would not meet all circumstances, and the DT elected to refrain from including any list.

The standard was revised so that an assessment is required annually unless changes in system conditions do not warrant an annual assessment – and entities must conduct at least one assessment every 5 years.

Commenter	Reliability Need	Acceptable Translation	Comments
Doug Hohbough – First Energy Corp.	Yes	Yes	The compliance reset timeframe should be five years. There would be no advantage to assessing compliance this year and returning next year to assess it again when the requirement is every 5 yrs.

Response: The compliance reset time period was left at one year. This does not mean that the Compliance Monitor must actively audit an entity every year.

Commenter	Reliability Need	Acceptable Translation	Comments
Dan Griffiths – PA Office of Consumer Advocate	Yes	Yes	
Howard Rulf - WE Energies	Yes	yes	
PPL Corporation	Yes	Yes	
Raj Rana – AEP	Yes	Yes	

Commenter	Reliability Need	Acceptable Translation	Comments
Deborah M. Linke – US Bureau of Reclamation	Yes	Yes	
Karl Kohlrus - City Water, Light & Power	Yes	Yes	
Carol L. Krysevig – Allegheny Energy Supply Co.	Yes	Yes	
Rebecca Berdahll – Bonneville Power Administration	Yes	Yes	
Karl Bryan – Corp of Engineers			
Jay Sietz – US Bureau of Reclamation			
Brenda Anderson			
Greg Mason – Dynergy Generation	Yes	Yes	

Members	Field Test Required?	Recommended Date?	Justification

Comments on Field Test and Effective Date

Summary Consideration: Most commenters did not indicate a need for field testing so the drafting team is not recommending it be field tested.

Peter Burke – American Transmission Co.	Yes		It would be unwise to require that assessment methods and criteria be established too quickly since there is presently no widely-accepted or well-proven methods and criteria in the industry.
Response: Most commenters did not indicate a need for field testing this standard. Please be more specific in identifying what you think needs to be field tested.			