Introduction

The first four sections of this document address comments received on the four SARs for the Phase III-IV Planning Standards, Questions 1, 2, 3, and 5. The final section addresses comments on each specific standard. These comments were received in response to Question 4 in the SAR posting, as well as comments received during the Version 0 standards project and comments received historically during the field testing and posting of planning standards.

List of Questions, Comments and Responses:

Question 1 – Scope of Work

Do you agree that the list of planning standards and measures indicated in the four SARs, taking in to consideration the standards already developed in Version 0, would complete the translation of all existing planning standards?"

Summary Consideration of Comments:

All Planning Standards removed from V0 have been addressed in this set of SARs. The following changes have been made:

- IIICM10 was listed under both the Disturbance Monitoring and Reporting Standards and in the Protection and Control Standards. This was corrected by eliminating the duplicate from the Disturbance Monitoring and Reporting.
- IIICM11 was not listed and should have been. IIICM1 has been added to the set of Standards for Protection and Control.
- IIIAM2 was erroneously listed in the set of SARs. IIIAM2 was never included in the set of Measures considered for development as a Version 0 Standard – this Measure was removed from the set of Planning Measures several years ago.

Several Stakeholders questioned the omission of I.F.S2.M6, "Use of Disturbance Data to Develop and Maintain Models". This Measure was re-identified as IFS2M5 by the Planning Committee several years ago and was included in the set of Measures included in these SARs.

Name	Contact Company	Answer Q1	Comment Q1
Kham Vongkhamchanh	Entergy Services, Inc.	NO	III.C.M11 is not included in the 4 SARs, however III.C.M10 is listed twice. The duplicate III.C.M10 was removed from the Disturbance Monitoring and Reporting Standards grouping, and III.C.M11was added to Protection and Control Standards grouping.
Brandon Snyder	Duke Energy		
Peter Burke	American Transmission Company		
John Horakh	MAAC	NO	Measurement III.C.S6.M11, "Analysis of misoperations of generator protection equipment", was removed from Version 0, but does not appear in any of the four SARs. It should be included in the Protection and Control SAR. Measurement III.C.S6.M10, "Procedure to monitor/ review/ analyze/ correct trip operations of generator protection equipment" is duplicated in both the Disturbance Monitoring and Reporting SAR and the Protection and Control SAR, should only be in the Protection and Control SAR The duplicate III.C.M10 was removed from the Disturbance Monitoring and Reporting Standards grouping, and III.C.M11was added to Protection and Control Standards grouping.
Peter Henderson	IESO		
Kathleen Goodman	ISO NE		
Karl Tammar	ISO/RTO Council		
Michael C. Calimano	NY Independent System		

	Operator		
Guy Zito	NPCC	NO	III C S6 M10 Is listed twice once in Disturbance Monitoring and once in the Protection and Control IIIC S6 M11 appears to be missing from the SARs perhaps these were a typo? The duplicate III.C.M10 was removed from the Disturbance Monitoring and Reporting Standards grouping, and III.C.M11was added to Protection and Control Standards grouping. IIIA S2 M2 is listed and was not part of the translation tables of Version 0- was this intentional what was the rationale. IIIAS2M2 was included in this set of SARs in error. This Measure was removed from the set of Planning Standards several years ago.
Michael C. Calimano	NY Independent System Operator	NO	Measurement I.F.S2.M6, "Use of Disturbance Data to Develop and Maintain Models", is missing and should be added. I.F.S2.M6 was re-designated as I.F.S2.M5 by the Planning Committee several years ago. IFS2M5 is included in the set of Measures addressed by these SARs.
Kathleen Goodman	ISO NE		IIIA S2 M2 is listed and was not part of the translation tables of Version 0- was this intentional what was the rationale and or the source document. IIIAS2M2 was included in this set of SARs in error. This Measure was removed from the set of Planning Standards several years ago.
Karl Tammar	ISO/RTO Council	NO	Measurement I.F.S2.M6, "Use of Disturbance Data to Develop and Maintain Models", is missing and should be added. I.F.S2.M6 was re-designated as I.F.S2.M5 by the Planning Committee several years ago. IFS2M5 is included in the set of Measures addressed by these SARs.
Allan Adamson	New York State Reliability Council (NYSRC)	NO	Measurement III.C.M10 is listed twice in the four SARs, while Measurement III.C.M11 is missing from these SARs. The duplicate III.C.M10 was removed from the Disturbance Monitoring and Reporting Standards grouping, and III.C.M11was added to Protection and Control Standards grouping. A Measurement III.A.M2 is included in Protection & Control SAR. We could not find this measurement on any NERC document listing Phase III & IV Measurements. IIIAS2M2 was included in this set of SARs in error. This Measure was removed from the set of Planning Standards several years ago.

Gerald Rheault	Manitoba Hydro	NO	The standards listed in these four SARs form the bulk of what is required to complete the translation but a couple (IIIC.M10 and IIIC.M11) were not included and should be. Further comments relative to these two standards are included in comment of question 3. Please see the summary consideration.
Lance Hall Doug Hils	Cinergy	NO	Assumed the drafting team has compared the Version 0 list and this latest list to determine if complete. Please see the summary consideration.
Marv Landauer	BPA	NO	I do not believe that the Version 0 standards with these four new SARs is an complete translation of the existing planning standards. I support the changes to the Planning Standards suggested by the Planning Standards Task Force that they submitted, especially pages 1-4. I have attached these comments verbatim below. Errata on Version 0 Planning Standards Recommended by the Planning Committee and the Planning Standards Task Force (November 22, 2004) TPL-001-0 (051.1) 1. Title: Remove the word “Assessments.” (This 051.1 standard, like standards 051.2, 051.3, and 051.4, is intended to describe system performance, not assessments. The assessments are a means to measure compliance with the standards. All four standards in this group need to have similar titles. Removing the word “assessments” will accomplish the needed consistency.) 3. Purpose: The standard defines the system performance that the transmission systems should be capable of achieving under a wide variety of system conditions while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits. This standard describes the required system performance under normal (no contingency) conditions. (The purpose as now stated in Version 0 is a compliance requirement, not the purpose of the standard. The purpose of the standard is specific system performance under specific conditions as mentioned at the November 9, 2004, PC meeting.)

This comment also applies to TPL-002-0 (051.2) and TPL-003-0 (051.3) with appropriate rewording in the last sentence.

4. Applicability

4.1 Add Transmission Owner (This standard, as pointed out at the November 9, 2004, PC meeting, was intended for the Transmission Owner who has ultimate responsibility for the planning, design, and construction of the transmission systems. Check the responsibility of transmission ownership in the functional model. See also the original planning standard, which specifically mentions the Transmission Owner.)

4.2 Transmission Planner (May be appropriate for the planning portion of this standard. Note that in the functional model the Transmission Planner needs to coordinate with the Transmission Owner and others, but is not responsible for the implementation of the plan. The Transmission Owner and Transmission Planner may be one and the same in the vertically integrated utility. The RTO or ISO may be the Transmission Planner in a deregulated open environment and must also meet the requirements of this standard.)

4.3 Planning Authority (May be appropriate for ensuring that a long-term plan is available for adequate resources and transmission within a Planning Authority Area, but does not have responsibility for the implementation of the plan. The Planning Authority could also be the Compliance Monitor depending on the organization structure.)

R.1 Requirements

The Transmission Owners, Transmission Planners, and Planning Authorities shall ensure that their portions of the interconnected transmission systems are planned, designed, and constructed such that, with ……., the network can deliver generator unit output to meet projected customer demands and …….in Category A of Table I. (The standard is to ensure that system performance is planned and built into the systems by the Transmission Owners ¾ the responsible entities. The intent of “delivering generator unit output” is to avoid bottled generator capacity. These elements have been eliminated in the Version 0 standard and should be reinstated. These comments also apply to TPL-002-0 (051.2) and TPL-003-0 (051.3)).

The Transmission Owners, Transmission Planners, and Planning Authorities also shall ensure that their transmission system capability and configuration, reactive power resources, protection systems, and control devices are adequate to ensure the system performance prescribed in Category A of Table I. (This sentence needs to be reinstated in TPL-001-0 (051.1) as well as TPL-002-0 (051.2) and TPL-003-0 (051.3).)

(Its inclusion in the original standard resulted in the elimination of a number of standards in other sections of the planning standards. For example, this sentence covers configuration and eliminates the need to address substation bus configurations ¾ straight bus, ring bus, breaker and a half, etc. The standard applies to all substation configurations.)

R1.3.9 in TPL-001-0 (051.1), TPL-002-0 (051.2), and TPL-003-0 (051.3) should read as follows:

Include the effects of existing and planned reactive power resources to ensure that adequate reactive resource are available to meet system performance. (This item needs to have parallel construction to the other items in the list of requirements. Also, the effects of reactive power are related to voltage.)

R1.3.12 Expand the requirement for TPL-002-0 (051.2) and TPL-003-0 (051.3) as follows.

Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed and be able to continue to operate within thermal, voltage, and stability limits under contingency conditions in Category B of Table I. (Category C of Table I for TPL-003-0 (051.3).)

(When planned or maintenance outages are performed, the clarification needs to be retained that with certain system elements removed, the system must be able to operate within defined limits for the contingencies of Categories B and C. All of the other conditions in the requirements being addressed involve planned additions to transmission facilities. It is important to make this distinction.)

R2.2 This section is confusing as rewritten. It is not clear what "(where sufficient lead time exists)" is intended to modify ¾ the assessments or the identified system facilities. Also, "Detailed implementation plans are not needed," as written appears to contradict R2-1. (The following original wording is again recommended to replace R2.2, "For identified system facilities for which sufficient lead times exist, detailed implementation plans are not needed. These system facilities shall be reviewed for continuing need in subsequent annual assessments." This comment also applies to TPL-002-0 (051.2) and TPL-003-0 (051.3).)

Table I Reinstate the "cascading outage" definition. (The definition of cascading outages was specifically developed for this standard and table and needs to be reinstated so that the table can be self-sustaining as originally intended, approved, and implemented. This cascading outage definition was critical in a recent detailed review of WECC bus section breaker failures and needs to be retained as are the other footnotes that are specific to the implementation of the table. There are many slight variations to the definition for cascading outage, which is why this one is important to this standard. Definitions that are specific to a standard and its implementation must be retained with the standard. The definition may also be included as one of the definitions in the glossary of terms, as appropriate. However, in general, the terms and their definitions in the glossary must emanate from the standards and not vice versa. A term may have more than one definition but its definition and specific intent and use in a standard are what is important, mandatory, and must be complied with and therefore retained with the standard. These comments apply to Table I in TPL-001-0 (051.1), TPL-002-0 (051.2), TPL-003-0 (051.3), and TPL-004-0 (051.4).)

The cascading definition in the Glossary is incorrect as it has been modified from the definition that appeared in Table I. Cascading is the successive loss (not necessarily failure) of system elements triggered by an incident at any location (within the Interconnection ¾ remove. There are three Interconnections and this is not relevant to the definition.). Cascading results in widespread electric service interruption that cannot be restrained form sequentially spreading beyond an area predetermined by appropriate studies. All wording in parentheses are not part of the original definition and should not be included.

TPL-004-0 (051.4)

3. Purpose: Incorrect as stated. Needs to be modified. (The purpose must be changed. It is not the same as TPL-001, 002, or 003, where reliable systems are to be developed. TPL-004 only evaluates the risks and consequences of a number of extreme contingencies. There are no requirements for planned upgrades or corrective plans.)

The following purpose is proposed:

Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. Actions to mitigate or eliminate the risks and consequences are at the discretion of the responsible entities. This standard identifies a number of extreme contingencies that are to be evaluated.

R1. The Transmission Owners, Transmission Planners, and Planning Authorities shall ensure that their portions of the interconnected transmission systems are evaluated for the risks and consequences of a number of each of the extreme contingencies listed under Category D of Table I. To ensure this evaluation, they shall assess and document the performance of their systems through valid assessments that shall include the following attributes:

			(The standard is to ensure that the Transmission Owners ¾ the responsible entities ¾ are aware of the performance of their systems under a number of extreme contingencies as they are the ones that will make investments to alleviate the risks. Transmission Planners and Planning Authorities may also perform these assessments and coordinate and review the results with the Transmission Owners.) R1.3.6 Requirement is incorrect and needs to be modified. ("To ensure that adequate reactive resources are available" needs to be removed. Reactive resources are not required to meet some level of system performance. Only the effects of existing or planned reactive resources need to be considered for the extreme contingencies. Corrective actions or plans are not required.) The following R1.3.6 is proposed: "Include the effects of existing and planned reactive resources." These comments have already been submitted and considered by the Version 0 Drafting Team.
Raj Rana	AEP	NO	It is assumed that the sum total of the effort would be a complete translation of Phases 3 and 4. Please see the summary consideration.
John Mulhausen	Florida Power & Light Co.	NO	

Roman Carter	Southern Company	YES	However, it is believed the list of Standards contained in the Phase III/IV Planning Standards go beyond what was intended to be developed by the U.S and Canada Blackout Investigation Task Force. Only those that address the Blackout recommendations and are significant in terms of improving reliability should be included in the subject SARs. This will promote the best utilization of Industry resources and enable them to focus on the more critical standards and issues. The Drafting Team believes that the NERC Board intended that almost all Phase III/IV Standards be included in these SARs. Please see the Summary of Consideration for each of the individual Measures under the consideration of comments submitted on Question 4. Some of the Phase III and IV Planning Standards are similar or redundant to Version 0 Standards that were extracted from the original NERC Operating Policies. These Planning Standards should either be excluded from the subject SARs or the Version 0 Standards should be included in the new SARs to avoid confusing or conflicting requirements. Agreed. The drafting team will attempt to avoid creating confusing, conflicting or duplicative requirements.
Kirit S. Shah	NERC Transmission Issues Subcomittee (TIS)	YES	TIS has no additional comments.
Kenneth John Dresner	First Energy Solutions	YES	
Ed Davis	Entergy Services	YES	
Tom Mielnik	MidAmerica Energy Company	YES	
Ray Morella	FirstEnergy Corporation	YES	
Ken Goldsmith	Alliant Energy	YES	
Karl A Bryan	US Army Corps of Engineers	YES	
Christopher Schaeffer	Duke Energy	YES	

Marc M. Butts	Southern Co.	YES
William J. Smith	Allegheny Power	YES

Question 2 – Reliability Need

Do you agree there is a reliability need for all of the standards proposed in these four SARs? If you have any concerns regarding reliability need, please note them in your comments.

Name	Contact Company	Answer Q2	Comment Q2
Kham Vongkhamchanh	Entergy Services, Inc.	NO	Some of the standards may have very limited application and some may not be practical to implement, as indicated in the responses to Question 4. Please see the detailed consideration of comments submitted in response to Question 4.
Christopher Schaeffer	Duke Energy	NO	Recommend an effort to compare the proposed Planning Standards with existing Operating Standards in version 0 to assure that time is not spent developing redundant standards and to assure there are not inconsistent standard requirements developed. For example; Operations Standard VAR-001-0 — Voltage and Reactive Control in the version 0 operating standards already addresses the issue of reporting generating unit AVR status. Thus, the Planning standards (III.C.S1.M1 and M2) on this issue are apparently redundant. If there are concerns associated with AVR status reporting that are not addressed by the Version 0 standard, it would be more appropriate to revise that standard as opposed to developing a new standard on that issue to avoid the potential for inconsistencies between two standards on the same issue. Operating Standard 014 - Monitoring System Conditions already addresses the issues covered by III.C.S2.M3 & M4 Standard 017 - System Protection Coordination already addresses the issues covered by III.C.S6.M10 and III.C.S7.M12. The drafting team has attempted to avoid creating confusing, conflicting or duplicative requirements. Please see the detailed consideration of comments submitted in response to Question 4.

Brandon Snyder	Duke Energy	NO	Recommend an effort to compare the proposed Planning Standards with existing Operating Standards in version 0 to assure that time is not spent developing redundant standards and to assure there are not inconsistent standard requirements developed. For example, Operations Standard VAR-001-0 — Voltage and Reactive Control in the version 0 operating standards already addresses the issue of reporting generating unit AVR status. Thus, the Planning standards (III.C.S1.M1 and M2) on this issue are apparently redundant. If there are concerns associated with AVR status reporting that are not addressed by the Version 0 standard, it would be more appropriate to revise that standard as opposed to developing a new standard on that issue to avoid the potential for inconsistencies between two standards on the same issue. Agreed. The drafting team has attempted to avoid creating confusing, conflicting or duplicative requirements. III.C.S6.M10 - Generator owners have an economic incentive to analyze and correct generator protective relay misoperations and thus, this standard is not necessary. Even though there is an economic incentive for generation owners to maximize their revenue and hence minimize unnecessary unit trips, this standard is still necessary to preserve the reliability of the interconnected bulk electric system.
Ken Goldsmith	Alliant Energy	NO	We question the need for all the data being requested in II.E.S1.M1-M3. We are not sure if it is possible to get all the data from customers to that level of detail. While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available.

Lance Hall	Cinergy	NO	Some of these proposed standards deal with reporting requirements and it is questionable that there is a direct link to reliability for those standards. Some contain requirements covered in the Version 0 standards and should be eliminated. Given the short amount of time allotted to develop these new standards, every effort should be made to reduce the number of standards with the goal of concentrating on performance requirements instead of prescriptive measures on how to achieve that performance. Without more specific information the Drafting Team is unable to provide a specific response. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.
Tom Mielnik	MidAmerica Energy Company	NO	I.F.S2.M5 is a vague enough measure that there is not a reliability reason for it. Also, II.B.S1.M1, II.B.S1.M4, II.B.S1.M5, and II.B.S1.M6 require expensive and possibly damaging testing that requires the Standards Drafting Team to balance the benefits of the standards against the costs generated by the standards. At a minimum, a statement should be added to these standards that "if safety and system conditions warrant, an alternative to testing should be allowed such as computations or engineering study." These standards require major rework and therefore, there is not a reliability reason for these to proceed similar to their present form. There is reliability reason for significantly revised versions of these standards. Also, II.E.S1.M1, II.E.S1.M2, and II.E.S1.M3 require extensive analysis. The Standards Drafting Team should balance the benefits of these standards against the costs generated by these standards. At a minimum, a statement should be added to these standards that "the load characteristic requirements are mandatory only for stability susceptible systems. IFS2M5 - Disturbance data must be provided to enable the development of accurate system models. II.B.S1.M1, II.B.S1.M4, II.B.S1.M5, and II.B.S1.M6 – The requirements to conduct generator testing have been revised to allow the use of any valid method for verifying models and data. IIEM1-M3 - While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads.

Peter Burke	American Transmission Company	NO	Scope of measurement I.D.M1 is implicitly covered by the intent of I.A. standards. It may be more useful to enhance the I.A. standards to explicitly state additional measures pertaining to reactive power assessment within the system performance assessment process. These measures should also address the relative mix of static and dynamic reactive reserves/margins. Many Stakeholders commented that IDM1 should not be moved forward because it is already covered in TPL-001-0, TPL-002-0, and TPL-003-0. The Drafting Team was concerned that while similar requirements are contained in the already approved TPL-001-0, TPL-002-0, and TPL-003-0 Standards, these V0 Standards do not require that there be a documented methodology and criteria for assessing reactive capabilities. The Blackout Report highlighted a need to pay particular attention to reactive resources. The Drafting Team added a requirement that the Planning Authority and Transmission Planner have a methodology and criteria for assessing adequate static and dynamic reactive power requirements. The Drafting Team will ask the Stakeholders if they agree with the new requirement and with keeping this Standard in the set of Standards being moved forward for approval. Scope of measurement III.B.M1 is implicitly covered by the intent of I.A. and II.A. standards. IIBM1 (Regional procedures for generation equipment testing) was modified and translated into a new Standard, MOD-023-1 (Procedures for Verifying Generation Equipment Data). The proposed Standard supports the intent of the original standard which was to ensure that generator models and data are accurate, while removing the requirement that generator testing be used to validate generator models and data. Many Stakeholders indicated that generator testing is not the only method for validating generator models and data. The revised Standard requires Regional Reliability Organizations (RROs) to establish and maintain procedures to address verification of generator modeling and equipment data. If necessary, it may be more useful to enhance the I.A. standards to explicitly state that both transmission elements and transmission control devices must be considered in the system performance assessment process. While the Drafting Team could have modified the IA and IIA Standards, an equally acceptable approach seemed to be to translate these Measures into new Standards.

Ed Davis	Entergy Services	NO	Some of the Phase III and Phase IV Planning Standards are superfluous. For example, the I.D measurements have been incorporated into the I.A measurements over the past several years. Flexibility must continue to exist to permit the Standards Drafting Team to eliminate those Standards which are no longer needed. Note that in the translation, the Drafting Team identified some Measures (including IDM2) that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.
Marv Landauer	BPA	NO	We believe that the requirements of NERC Planning Standard I.D, System Adequacy and Security and Voltage Support and Reactive Power, are adequately addressed in other NERC Reliability Standards (Planning Standard I.A, System Adequacy and Security, Transmission Systems, and its equivalents in the NERC Version 0 Reliability Standards). Standard I.D is therefore redundant. A proper "balance" between static and dynamic characteristics is dependant on integrated design and practices of the distribution, transmission and generation systems. Thus the balance between static and dynamic characteristics can be different, but at the same time compliant with all NERC Standards (including Table I of Standard I.A). Note that in the translation, the Drafting Team identified some Measures (including IDM2) that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc. We believe that the guidelines that are currently part of Standard I.D are useful and important in the transmission planning process. These guidelines, considered as best practices, should be retained and incorporated in the NERC standards. The current NERC Standards template does not have a place for "Guidelines". If it is not a requirement that can be measured, it cannot be part of the standards. The Drafting Team agrees that the guidelines provide valuable additional information, but these guidelines should be part of a separate supplement to the NERC Standards, not part of the Standards themselves. We recommend verification and benchmarking of data and models for voltage control and reactive planning. Verification should include real and reactive capability of generators, generator characteristics incorporated into models, generator step up transformer characteristics, load power factor, and load models.

			Please see the set of proposed standards and let us know if we've missed anything.
Doug Hils	Cinergy	NO	Some of these proposed standards deal with reporting requirements and it is questionable that there is a direct link to reliability for those standards. Some contain requirements covered in the Version 0 standards and should be eliminated. Given the short amount of time allotted to develop these new standards, every effort should be made to reduce the number of standards with the goal of concentrating on performance requirements instead of prescriptive measures on how to achieve that performance. Without more specific information regarding which proposed standards are being referred to, the Drafting Team is unable to provide a specific response. However, the drafting team has attempted to avoid creating confusing, conflicting or duplicative requirements in these Phase III/IV Standards. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.
John Mulhausen	Florida Power & Light Co.	NO	
Kirit S. Shah	NERC Transmission Issues Subcomittee (TIS)	YES	TIS believes that the requirements of NERC Planning Standard I.D, System Adequacy and Security and Voltage Support and Reactive Power, are adequately addressed in other NERC Reliability Standards (Planning Standard I.A, System Adequacy and Security, Transmission Systems, and its equivalents in the NERC Version 0 Reliability Standards). Standard I.D is therefore redundant. A proper "balance" between static and dynamic characteristics is dependant on integrated design and practices of the distribution, transmission and generation systems. Thus the balance between static and dynamic characteristics can be different, but at the same time compliant with all NERC Standards (including Table I of Standard I.A). Without more specific information regarding which proposed standards are being referred to, the Drafting Team is unable to provide a specific response. Note that in the translation, the Drafting Team identified some Measures (including IDM2) that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc. TIS believes that the guidelines that are currently part of Standard I.D are useful and

			important in the transmission planning process. These guidelines, considered as best practices, should be retained and incorporated in the NERC standards. The current NERC Standards template does not have a place for "Guidelines". If it is not a requirement that can be measured, it cannot be part of the standards. The Drafting Team agrees that the guidelines provide valuable additional information, but these guidelines should be part of a separate supplement to the NERC Standards, not part of the Standards themselves. TIS supports and recommends verification and benchmarking of data and models for voltage control and reactive planning. Verification should include real and reactive capability of generators, generator characteristics incorporated into models, generator step up transformer characteristics, load power factor, and load models. TIS will follow and comment on the development of any NERC Reliability Standards that are to replace the Phase III and Phase IV Planning Standards that relate to this recommendation. Please see the set of proposed standards and let us know if we've missed anything.
Roman Carter	Southern Company	YES	It is agreed these Standards are reliability related but not sure all of them should be sent through this "accelerated" standard development process. See our response to question 1 above. Some examples of the standards which fit this category are: II.E.M.1-3 - Do not believe these 3 Standards are vital to the Blackout recommendation and could be developed under the normal NERC process. While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available. III.C.S6.M10 - Generator owners already have an incentive to analyze and correct generator protective relay misoperations. Even though there is an economic incentive for generation owners to maximize their revenue and hence minimize unnecessary unit trips, this standard is still necessary to preserve the reliability of the interconnected bulk electric system.

II.D.M.3- Should not be included in these SARs. It should be developed under the normal NERC process.

IIDM3 (Procedures Requiring Consistency of Data) was not translated because Stakeholders indicated the Measure is not needed for reliability.

II.B.S1.M5- Work on this standard should be postponed until better technical direction has been developed.

IIBM5 (Test Results of Speed/Load Governor Controls) was merged with IIBM9 (Speed/Load Governing System) and converted into a new Standard, MOD-027-1 (Verification and Status of Generator Frequency Response). The new Standard supports the intent of both of the original Measures, which was to provide verification and status of generator frequency response for use in models for reliability studies.

The original requirements to conduct generator testing were replaced with requirements for Generator Owners to 'verify' their data – the revised Requirements do not specify 'how' the Generator Owner must verify its data. Many Stakeholders indicated that generator testing is not the only method for verifying generator data and many Stakeholders indicated that re-validating data every five years may not be appropriate. Other Stakeholders indicated concerns that testing may not be feasible. The Drafting Team recognizes that there are technical issues with the speed governor models that need to be resolved. The proposed standard simply requires the Generator Owners to evaluate how their unit's MW output is expected to respond to frequency and report that information to the Transmissions Planner and Regional Reliability Organization (RRO). The revised Standard requires Generator Owners to document their method of verifying generator data in a manner that meets the associated RRO's requirements. The new proposed standard does not include any requirement that identifies the specificity for generator modeling and equipment data verifications.

III.C.S1.M1 and M2 -Voltage and Reactive Control in the Version 0 Operating standards already addresses the issue of reporting generating unit AVR status. Thus, the Planning standards on this issue are apparently redundant. If there are concerns associated with AVR status reporting that are not addressed by the Version 0 Standard, it would be more appropriate to revise that Standard as opposed to developing a new standard on that issue to avoid the potential for inconsistencies between two standards on the same issue.

IIICM1 (Operation of all Synchronous Generators in the Automatic Voltage Control Mode - Documentation) was merged into the already approved VAR-001-1 (Voltage and Reactive

			Control). Several Stakeholders indicated they felt that M1 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM1. IIICM1 requires the Transmission Operator to have procedures requiring each Generator Operator with one or more synchronous generators connected to its system to provide information relative to operating in the automatic mode. VAR-001 does not contain any similar requirements. Several Stakeholders indicated they felt that M1 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM1. IIICM1 requires the Transmission Operator to have procedures requiring each Generator Operator with one or more synchronous generators connected to its system to provide information relative to operating in the automatic mode. VAR-001 does not contain any similar requirements. Several Stakeholders indicated they felt that M2 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM2. VAR-001 contains a requirement for the Generator Operator to provide information to its Transmission Operator on the status of its reactive power resources – and IIICM2 requires the Generator Operator to operate its synchronous generating units in the automatic voltage control mode unless otherwise approved by the Transmission Operator. These are two different requirements, so the Drafting Team did not remove IIICM2 from the set of Standards being moved forward for approval.
Marc M. Butts	Southern Co.	YES	While we agree that there is a reliability need for reasonably accurate information and standards that are practical and reasonably implementable, there is not a reliability need for these standards in the exact form as they currently exist. Further comments to this effect are included in more detail in the Challenges to Achieving Consensus section of this document. We are not sure all of them should be sent through this "accelerated" standard development process. Examples of the standards which fit this category are: II.E.M.1-3 - Do not believe these 3 Standards are vital to the Blackout recommendation and could be developed under the normal NERC process. While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available.

			III.C.S6.M10 - Generator owners already have an incentive to analyze and correct generator protective relay misoperations. Even though there is an economic incentive for generation owners to maximize their revenue and hence minimize unnecessary unit trips, this standard is still necessary to preserve the reliability of the interconnected bulk electric system. II.D.M.3- Should not be included in these SARs. It should be developed under the normal NERC process. The Drafting Team believes that the NERC Board intended that almost all Phase III/IV Standards be included in these SARs. III.C.S1.M1 and M2 -Voltage and Reactive Control in the Version 0 Operating standards already addresses the issue of reporting generating unit AVR status. Thus, the Planning standards on this issue are apparently redundant. If there are concerns associated with AVR status reporting that are not addressed by the Version 0 Standard, it would be more appropriate to revise that Standard as opposed to developing a new standard on that issue to avoid the potential for inconsistencies between two standards on the same issue Several Stakeholders indicated they felt that M1 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM1. IIICM1 requires the Transmission Operator to have procedures requiring each Generator Operator with one or more synchronous generators connected to its system to provide information relative to operating in the automatic mode. VAR-001 does not contain any similar requirements. Several Stakeholders indicated they felt that M2 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM2. VAR-001 contains a requirement for the Generator Operator to provide information to its Transmission Operator on the status of its reactive power resources – and IIICM2 requires the Generator Operator to operate its synchronous generating units in the automatic voltage control mode unless otherwise approved by the Transmission Operator. These are two different requirements, so the Drafting Team did not remove IIICM2 from the set of Standards being moved forward for approval.
Allan Adamson	New York State Reliability Council (NYSRC)	YES	Except for Measurement III.A.M2 (discussed in our response to Question 1), we agree the there is a reliability need for all the standards proposed in the four SARs. IIIAM2 was included in this set of SARs in error.

Gerald Rheault	Manitoba Hydro	YES
Raj Rana	AEP	YES
Ray Morella	FirstEnergy Corporation	YES
John Horakh	MAAC	YES
William J. Smith	Allegheny Power	YES
Peter Henderson	IESO	YES
Kathleen Goodman	ISO NE	YES
Kenneth John Dresner	First Energy Solutions	YES
Guy Zito	NPCC	YES
Karl Tammar	ISO/RTO Council	YES
Michael C. Calimano	NY Independent System Operator	YES
Karl A Bryan	US Army Corps of Engineers	YES

Question 3 – Grouping of the Standards for Development Purposes

Because the proposed scope of work is large, the requester has grouped the proposed standards into four SARs. Do you agree this is an appropriate way to organize the work? What improvements would you suggest to grouping the development work?

Summary Consideration: The Drafting Team considered the many different suggestions provided, and determined that there is no single method of organizing the Measures associated with these SARs that will meet everyone's suggestions. Since each of the SARs is being converted to several different Standards, finding a 'perfect' alignment isn't essential.

- Several Stakeholders suggested that these Measures be re-grouped according to applicable entity, with all Measures under the responsibility of the Generator Owner or Generator Operator grouped into a single set. NERC has plans to build a relational database for Reliability Standards that will be searchable by applicability (e.g., Generator Owner, Transmission Operator), so organizing all the Measures by applicable entity doesn't seem needed.
- Several Stakeholders suggested realignment according to topic. NERC has already established a system for categorizing its Reliability Standards. This system includes the following large categories. The set of Measures included in the four SARs and the titles of their associated proposed Standards are shown under their associated categories highlighted in yellow. The Drafting Team re-organized the SARs according to these categories. (Note that some of the Measures were merged together to form either a new Standard or to modify an existing approved Version 0 Standard – for more information on the reasoning for the rearrangements, see the responses to Question 4. Measures that Stakeholders indicated should move forward are shown in blue – Measures that Stakeholders indicated should be deleted are shown in red.)

This shall serve as a summary response to all comments submitted with suggestions for re-grouping.

BAL	Resource and Demand Balancing
CIP	Critical Infrastructure Protection
COM	Communications
EOP	Emergency Preparedness and Operations
	IVAM2 – System restoration pans
	IVAM3 – System restoration plans
	IVBM1 – Document automatic load restoration program
	IVBM2 – Document automatic load restoration program with Regional requirements
	IVBM3 – Assess effectiveness of automatic load restoration programs
	IVBM4 – Document automatic load restoration equipment testing/maintenance program
FAC	Facilities Design, Connections and Maintenance
INT	Interchange Scheduling and Coordination
IRO	Interconnection Reliability Operations and Coordination

MOD Modeling, Data, and Analysis

- IFM5 – Use of disturbance data to develop and maintain models
- IIBM1 – Regional procedures for verifying generation equipment data
- IIBM2 – Verification of generator gross and net dependable capability
- IIBM3 – Verification of reactive power capability
- IIBM4 – Verification of modeling of generator excitation systems and voltage controls
- IIBM5 – Verification and status of generator frequency response
- IIBM6 – Verification of modeling of generator excitation systems and voltage controls
- IIDM2 – Documentation of data reporting requirements for actual and forecast demands, net energy for load and controllable demand-side management
- IIDM3 – Reporting procedures to ensure against double counting or omission of customer demand data
- IIEM1 – Plans for evaluation and reporting of voltage & frequency characteristics of customer demands
- IIEM2 – Documentation of requirements for determining dynamic characteristics of customer demands
- IIEM3 – Customer (dynamic) demand data
- IIIBM1 – Assessment of reliability impact of transmission control devices
- IIIMB2 – Provision of models and data for transmission power electronic control devices
- IIIMB3 – Provision of models and data for transmission power electronic control devices
- IIICM9 – Verification and status of generator frequency response

ORG Organization Certification

PER Personnel Performance, Training, and Qualifications

PRC Protection and Control

- IFM2 – Disturbance monitoring equipment list
- IFM3 – Disturbance monitoring data reporting requirements
- IFM4 – Disturbance data reporting
- IIICM8 – Coordination of generator controls with generator capabilities
- IIICM10 – Regional procedure for transmission and generation protection system misoperations
- IIICM11 – Analysis and reporting of transmission and generation protection system misoperations
- IIICM12 – Transmission and generation protection system maintenance and testing
- IIIEM1 – Under-voltage load shedding program data
- IIIEM2 – Under-voltage load shedding program database
- IIIEM3 – Under-voltage load shedding program performance

TOP Transmission Operations

TPL Transmission Planning

VAR Voltage and Reactive

- IDM1 – Assessment of Reactive Power Resources
- IDM2 – Reporting procedures that ensure against double counting or omission of customer demand data
- IIICM1 – Voltage and reactive control
- IIICM2 – Generator operation for maintaining network voltage schedules
- IIICM3 – Voltage and reactive control
- IIICM4 – Generator operation for maintaining network voltage schedules

IIICM5 – Voltage and reactive control
IIICM6 – Generator operation for maintaining network voltage schedules
IIICM7 – Generator performance during temporary frequency and voltage excursions

Name	Contact Company	Answer Q3	Comment Q3
Kham Vongkhamchanh	Entergy Services, Inc.	NO	Measurements III.C.M10 and M11 should both be in the Protection and Control SAR.
Christopher Schaeffer	Duke Energy	NO	To facilitate generation industry involvement, group all the generator-applicable requirements in the Disturbance Monitoring and Reporting, Modeling and the Protection and Control SAR's to permit a team composed of industry generation and transmissions representatives to focus on those requirements.
John Mulhausen	Florida Power & Light Co.	NO	
Ray Morella	FirstEnergy Corporation	NO	II.D.S1.M2 and II.D.S1-S2.M3 should be moved to the Modeling SAR.

Michael C. Calimano Kathleen Goodman Karl Tammar	NY Independent System Operator New England ISO ISO/RTO Council	NO NO NO	The following Measurements do not belong in the Disturbance Monitoring and Reporting SAR: II.D.S1.M2, "Reporting procedures that ensure against double counting or omission of customer demand data" - Move to Modeling SAR II.D.S1-S2.M3, "Procedures requiring consistency of data reported for reliability purposes and to gvt agencies" - Move to Modeling SAR III.C.S6.M10, "Procedure to monitor/ review/ analyze/ correct trip operations of generator protection equipment" - Move to Protection and Control SAR I.F.S2.M5, "Use Database" does not belong in the Disturbance Monitoring and Reporting SAR. - Move to Modeling SAR. The following Measurements do not belong in the Modeling SAR: III.C.S3.M7, "Requirements for withstanding temporary excursions in frequency, voltage, etc" - Move to Protection and Control SAR III.C.S4.M8, "Info on generator controls coordination with unit's short-term capabilities & protective relays" - Consider whether this better fits in the Protection and Control SAR III.C.S1.M1-M2 "Generation Voltage Control" and III.C.S2.M3-M4 "Voltage Schedules" are more closely associated with VAR-001 in Version 0 than they are with modeling. They should be placed in VAR-001 as a Version 1 change rather than placed in this Modeling SAR.
Lance Hall	Cinergy	NO	The term "modeling" is somewhat mis-leading considering the measures included in that group. Several of these measures include requirements for generator testing and a generator owner may not realize this and skip over reviewing them. A more descriptive name should be used such as "Modeling and generator testing and reporting".
Tom Mielnik	MidAmerica Energy Company	NO	III.C.S6.M10 should be in the SAR-Protection and Control Group. A System Planning SAR group should have been formed for planning standards such as II.D.S1.M2, II.D.S1-S2.M3, II.D.S1.M1, II.E.S1.M1, II.E.S1.M2, II.E.S1.M3, and III.A.S2.M2.

Peter Burke	American Transmission Company	NO	1. Disturbance Monitoring SAR: i) Remove measurement III.C.M10 since it is already listed in the Protection and Control SAR (where it rightfully belongs). ii) Remove measurements II.D.M2-M3 since they do not pertain to disturbance monitoring. Suggest including them in a separate group along with measurements II.E.M1-M3; this may be within the Modeling SAR (see Customer Demand Data group 3e proposed below), or it may be a new SAR on Customer Demand Data. 2. Protection and Control SAR: i) Add missing measurement III.C.M11 to complete the set of generator protection measures. ii) Remove measurement III.B.M1 from this SAR since it is weakly related to protection & control. Suggest that III.B.M1 be included in the same SAR that addresses I.D.M1 (see comments to Q.2) since they both pertain to system performance assessment. iii) Move measurement III.B.M2 to the Modeling SAR since it pertains to modeling of transmission control devices. 3. Modeling SAR: Would organize work into smaller groups and suggest following grouping for modeling standards development: a) Generator Capability: I.D.S1.M2, Generation reactive power capability. II.B.S1.M1, Procedures for validating generation equipment data. II.B.S1.M2, Verification of gross & net dependable capability. II.B.S1.M3, Verification of gross & reactive power capability of generators. b) Generator Control/Regulation: II.B.S1.M4, Test results of generator voltage regulator controls & limit functions.

II.B.S1.M5, Test results of speed/load governor controls.

II.B.S1.M6, Verification of excitation system dynamic modeling data.

III.C.S3.M8, Information on generator controls coordination with unit's short-term capabilities & protective relays

III.C.S3.M9, Information on speed/load governoring system.

c) Generator Transformation:

III.C.S2.M5, Reporting Procedures for tap settings of generator step-up & auxiliary transformers.

III.C.S2.M6, Tap settings Data of generator step-up & auxiliary transformers.

d) System Operations Regulation:

III.C.S1.M1, Procedure by Sys Operator for reporting operation without automatic voltage control mode.

III.C.S1.M2, Log of operation without automatic voltage control mode by gen owner.

III.C.S2.M3, Documentation of schedule for maintaining network voltage.

III.C.S2.M4, Log operation not maintaining network voltage schedules.

III.C.S3.M7, Requirements for withstanding temporary excursions in frequency, voltage, etc.

e) Customer Demand Data:

II.E.S1.M1, Plans for the evaluation and reporting of voltage & frequency characteristics of customer demands.

II.E.S1.M2, Documentation of requirements for determining dynamic characteristics of customer demands.

II.E.S1.M3, Customer (dynamic) demand data.

			plus the following two measures moved from the Disturbance Monitoring SAR II.D.S1.M2, Reporting Procedures that ensure against double counting or omission of customer demand data. II.D.S1-S2.M3, Procedures requiring consistency of data reported for reliability purposes and to government agencies
Brandon Snyder	Duke Energy	NO	To facilitate generation industry involvement, group all the generator-applicable requirements in the Disturbance Monitoring and Reporting, Modeling and the Protection and Control SAR's to permit a team composed of generation and transmissions representatives to focus on those requirements.
Gerald Rheault	Manitoba Hydro	NO	The grouping in the Modeling Sar includes a number of standards related to generator performance which do not belong in this Modeling Standard. These are IIIC.M1 to IIIC.M4, IIIC.M7, andIIIC.M8. These standards should be in a separate new Standard. Standard IIIC. M10 is located in two different Standards and IIIC.M11 and IIIC.M12 are not included in any of the Standards and should be included in a generator performance grouping.
Marv Landauer	BPA	NO	Although it is hard to fit these diverse standards within four SARs, the following groupings do not seem appropriate. Standards III.E.S1.M1, M2, M3 are now included in the Protection and Control Standards but they do not seem to fit since they refer to UVLS programs. Standards III.C seem to be more operationally oriented rather than the modeling group they were put in. For example, reporting requirements for operation in automatic voltage control mode is does not seem to fit with modeling. Standards II.D.S1.M2 and II.D.S1-S2.M3 are related more to modeling than disturbance monitoring.

Allan Adamson	New York State Reliability Council (NYSRC)	NO	The NYSRC believes that four proposed SAR measurement groups are disjointed. Certain SAR groups presently contain unrelated measurements. For example, the Black Start Capability SAR includes Automatic Restoration of Load measurements IV.B.M1-4, which are unrelated to black start; and the Modeling SAR includes several non-modeling measurements, i.e., Generation Protection & Control measurements III.C.M1-9. Also, certain related measurements are spread into different SAR groups. For example, the Phase III & IV measurements related to Generation Control and Protection (III.C) are separated into three different SAR groupings.
Doug Hils	Cinergy	NO	The term "modeling" is somewhat mis-leading considering the measures included in that group. Several of these measures include requirements for generator testing and a generator owner may not realize this and skip over reviewing them. A more descriptive name should be used such as "Modeling and generator testing and reporting".
Guy Zito	NPCC	NO	NPCC Has concerns that the grouping is disjointed. There are groupings done that place standards together that don't appear to have anything in common. We would suggest that for the purposes of development-the standards regrouped into the four categories and the technical drafting teams then be formed.
Kenneth John Dresner	First Energy Solutions	NO	
John Horakh	MAAC	YES	The following Measurements do not belong in the Disturbance Monitoring and Reporting SAR: II.D.S1.M2, "Reporting procedures that ensure against double counting or omission of customer demand data" - Move to Modeling SAR II.D.S1-S2.M3, "Procedures requiring consistency of data reported for reliability purposes and to gvt agencies" - Move to Modeling SAR III.C.S6.M10, "Procedure to monitor/ review/ analyze/ correct trip operations of generator protection equipment" - Move to Protection and Control SAR The following Measurements do not belong in the Modeling SAR: III.C.S3.M7, "Requirements for withstanding temporary excursions in frequency, voltage, etc" - Move to Protection and Control SAR III.C.S4.M8, "Info on generator controls coordination with unit’s short-term capabilities & protective relays" - Move to Protection and Control SAR

Marc M. Butts	Southern Co.	YES	Several referenced standards seem to be in the incorrect SAR grouping and one is double counted in both the Disturbance Monitoring and Reporting SAR and the Protection and Control SAR. -II.D.S1.M1 and II.D.S1-S2.M3 need to be moved from the Disturbance Monitoring and Reporting SAR to the Modeling SAR. -III.C.S6.M10 is listed in both the Disturbance Monitoring and Reporting SAR and the Protection and Control SAR. It needs to be removed from the Disturbance Monitoring and Reporting SAR. -III.C.S1.M1, III.C.S1.M2, III.C.S2.M3, III.C.S2.M4, III.C.S2.M5, and III.C.S2.M6 need to be moved from the Modeling SAR to the Disturbance Monitoring and Reporting SAR. Recommend comparing and collating the proposed Planning Standards with existing Operating Standards in Version 0 before moving forward with these SARs to assure that time is not spent developing redundant standards and to ensure inconsistent Standard requirements are not developed. Where duplications occur, it is recommended the Version 0 Standard be removed, and transferred to the Phase III/IV Planning Standards. Operations Standard VAR-001-0 — Voltage and Reactive Control in the Version 0 Operating standards already addresses the issue of reporting generating unit AVR status. Thus, the Planning standards (III.C.S1.M1 and M2) on this issue are apparently redundant. If there are concerns associated with AVR status reporting that are not addressed by the Version 0 Standard, it would be more appropriate to revise that Standard as opposed to developing a new standard on that issue to avoid the potential for inconsistencies between two standards on the same issue.
Roman Carter	Southern Company	YES	Recommend comparing and collating the proposed Planning Standards with existing Operating Standards in Version 0 before moving forward with these SARs to assure that time is not spent developing redundant standards and to ensure inconsistent Standard requirements are not developed. Where duplications occur, it is recommended the Version 0 Standard be removed, and transferred to the Phase III/IV Planning Standards. To facilitate Generation Industry involvement, it is recommended NERC bundle the generator-applicable requirements in the Disturbance Monitoring and Reporting, Modeling, and the Protection and Control SAR's into one Standard to best utilize the generation representative's expertise in focusing on those requirements. Operations Standard VAR-001-0 — Voltage and Reactive Control in the Version 0

			Operating standards already addresses the issue of reporting generating unit AVR status. Thus, the Planning standards (III.C.S1.M1 and M2) on this issue are apparently redundant. If there are concerns associated with AVR status reporting that are not addressed by the Version 0 Standard, it would be more appropriate to revise that Standard as opposed to developing a new standard on that issue to avoid the potential for inconsistencies between two standards on the same issue.
Ed Davis	Entergy Services	YES	III.C.M10 should be deleted from the Monitoring SAR. It is duplicated in the Protection SAR, which is where it should reside. III.C.M11 should be added to the Protection SAR. It is not included on any SAR.
Ken Goldsmith	Alliant Energy	YES	While we agree that most of the functions are necessary, we as stakeholders need some assurances that there will not be overlap, duplication by RRO's, and overly costly to implement.
Peter Henderson	IESO	YES	The following Measurements do not belong in the Disturbance Monitoring and Reporting SAR: II.D.S1.M2, "Reporting procedures that ensure against double counting or omission of customer demand data" - Move to Modeling SAR II.D.S1-S2.M3, "Procedures requiring consistency of data reported for reliability purposes and to gvt agencies" - Move to Modeling SAR III.C.S6.M10, "Procedure to monitor/ review/ analyze/ correct trip operations of generator protection equipment" - Move to Protection and Control SAR The following Measurements do not belong in the Modeling SAR: III.C.S3.M7, "Requirements for withstanding temporary excursions in frequency, voltage, etc" - Move to Protection and Control SAR III.C.S4.M8, "Info on generator controls coordination with unit's short-term capabilities & protective relays" - Consider whether this better fits in the Protection and Control SAR III.C.M1 to M4 these could be better severed as a separate SARs to align with the version 0 standard already developed instead of as part of the modeling SAR. They specify requirements to maintain reactive resources and voltage level and are closer aligned to Version 0 standard VAR-001. These should be grouped as a separate SAR to ensure consistency, eliminate duplication and incorporated as additional requirements to standard

			Version 0 standard VAR-001
Raj Rana	AEP	YES	Subdividing the task is necessary. The approach is reasonable.
Kirit S. Shah	NERC Transmission Issues Subcomittee (TIS)	YES	TIS agrees with the four groups for the proposed standards, however some TIS members have commented on the possible duplication of standards in more than one group. A number of TIS members will comment on this subject separately.
Karl A Bryan	US Army Corps of Engineers	YES	
William J. Smith	Allegheny Power	YES	

Question 5 – Additional General Comments

Please provide any additional comments you have regarding the proposed development of Phase III-IV planning standards that were not developed in Version 0.

Name	Contact Company	Comment Q5
Kham Vongkhamchanh	Entergy Services, Inc.	Although III.C.M11 is not listed in Question 4, we feel this measurement should be classified as Medium. We offer the following comments: The measurement should be revised to only require documentation of misoperations. Documentation of the analysis of all operations should not be required. The second paragraph of the measurement should be revised to: Documentation of the analysis of misoperations and corrective actions shall be provided to the affected Regions and NERC on request (30 business days). III.C.M11 was omitted in error and has been added to Protection and Control Standards grouping and translated into the already approved V0 Standard, PRC-004-1. While the proposed Standard does not include the exact wording you've suggested, the intent of your suggestion is supported in the proposed Standard. Nuclear plants have formal Problem Investigation processes with defined time guidelines and manage their resources accordingly. In some cases, this process may allow for more than 30 days to complete investigations into causes of trips. The NERC requirement should not impose unnecessary time requirements more restrictive than existing processes. The proposed Standard does include providing an analysis and mitigation plan within 30 days of a 'request' – the 30 days is not tied to the date of the misoperation 'event'. In developing these SARs, recognition needs to be given to data requested that may be considered Critical Energy Infrastructure Information. These SARs need to recognize the confidential nature of that data. Agreed. The proposed Standards do not require distribution of data that may be considered Critical Energy Infrastructure information.

Karl A Bryan	US Army Corps of Engineers	Recommend serious consideration be given to a national certification program for operators (both transmission system and generating facility) as well as a certification program for maintenance personnel that work on some of the more critical components in the power train. The certification program should require continuing education credits and the certification program should meet a minimum level of accreditation. Addressing personnel certification is outside the scope of this set of SARs. These SARs are associated with Phase III & IV Planning Measures that weren't translated into Version 0 Standards.
John Horakh	MAAC	See additional detailed comments on the II.B.S1.M1-M6 Measurements (System Modeling Data Requirements - Generation Equipment) in the separate document titled "MAAC Position Paper on Generator Testing to Verify Data Required for System Modeling", dated January 8, 2001. Although this document is four years old, the comments in the document are still applicable because these Measurements have not been field tested or changed. The following quotes from this document are relevant: "The MAAC Region endorses the intent of this Standard" (II.B.S1) "The MAAC Region believes that these Measurements" (II.B.S1.M1-M6) "are very important to ensure that the necessary generator modeling data is verified and provided" "However, MAAC believes the Measurements as currently written are overly restrictive". Modification of these Measurements is desirable using the "open" Reliability Standards process which has been initiated with these SARs. Many Stakeholders indicated that these Measures should be modified to include all valid methods of verifying models and data, not just generator testing. In translating the Planning Measures into Reliability Standards, the Drafting Team eliminated the references to generator testing. As you've suggested, this is just one method of verifying models and data, and not the only valid method. The proposed Standards require that models and data be verified, but don't specify 'how'.

Ray Morella Kenneth John Dresner	FirstEnergy Corporation First Energy Solutions	Disturbance Monitoring and Reporting: - The drafting team should include expertise from both the transmission and generation owners. The Drafting Team appointed to address the SARs and to draft the associated Standards does include members from both transmission and generation functions. - It seems as though some of the standards referenced in the detailed description are outside of the Phase III/IV category resulting in some overlap with the Version 0 standards. Are all of the standards listed in the detailed description untested? All of the Measures listed in the set of SARs were omitted from Version 0, with the exception of IIIAM2 which was included in this set of SARs in error. Phase III Measures were field tested, but Phase IV measures have not been field tested. Protection and Control: - The drafting team should include expertise from both the transmission and generation owners. The Drafting Team appointed to address the SARs and to draft the associated Standards does include members from both transmission and generation functions.

Peter Henderson	IESO	For periodic testing of generator capabilities, it could be problematic to determine how to consistently conduct tests. In addition, there are difficult financial issues to be dealt with. In translating the Planning Measures into Reliability Standards, the Drafting Team eliminated the references to generator testing. Many Stakeholders indicated that this is just one method of verifying models and data, and not the only valid method. The proposed Standards require that models and data be verified, but don't specify 'how'. Based on previous experience, determination of dynamic load modeling will be a challenge. While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available. It is not clear why the System Restoration standards (IV.B….) are being pushed through this process. The importance of these particular standards does not seem to warrant fast tracking rather than going through normal due process. Version 0 already has requirements for restoration plans, so any standards developed here should be coordinated with existing Version 0 standards (EOP-005, R7 and R8) to assure consistency. All of the Planning Measures, (including those that address Blackstart Units and Automatic Load Restoration Programs) that were dropped from the V0 Standards are included in this set of SARs. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.
Marc M. Butts	Southern Co.	To have any Standard go through the SAR and Standard development process and be adopted by the Board in less than six months is almost an impossible task without being an Urgent Action Standard. To think that all the Standards contained in the Phase III/IV Planning Standards can go through the ANSI Standard Process and the NERC Process Manual procedures and be adopted in less than six months is even a larger (if that is possible) task to accomplish. We are concerned that errors and/or technically unsound requirements will occur. Additionally, if no field testing occurs or if Industry consensus is not reached may result in doing the wrong thing for the right reason and could result in increasing the chances for a system disturbance rather than preventing one.

		This is a monumental task, but is necessary to fill holes in the current standards. Many of these Measures have already been field tested and just lack minor modifications to reflect the findings from that field testing. Although III.C.M11 is not listed in Question 4, we feel this measurement should be classified as Medium. We offer the following comments: The measurement should be revised to only require documentation of misoperations. Documentation of the analysis of all operations should not be required. The second paragraph of the measurement should be revised. IIICM11 was omitted in error – it has been added to the set of Measures under Protection and Control. The proposed translation does not require documentation of operations – but does require documentation of misoperation analyses and associated mitigation plans. Documentation of the analysis of misoperations and corrective actions shall be provided to the affected Regions and NERC on request (30 business days). The proposed translation does include this requirement – but the term, 'corrective actions' has been replaced with the term, 'mitigation plans'. Nuclear plants have formal Problem Investigation processes with defined time guidelines and manage their resources accordingly. In some cases, this process may allow for more than 30 days to complete investigations into causes of trips. The NERC requirement should not impose unnecessary time requirements more restrictive than existing processes. The proposed Standard does include providing an analysis and mitigation plan within 30 days of a 'request' – the 30 days is not tied to the date of the misoperation 'event'. In developing these SARs, recognition needs to be given to data requested that may be considered Critical Energy Infrastructure Information. These SARs need to recognize the confidential nature of that data. Agreed. The proposed Standards do not require distribution of data that may be considered Critical Energy Infrastructure information.
Raj Rana	AEP	I.F.M1-M5 need to be revised. The deficiencies of these Measurements were identified by NERC IDWG in its report to NERC PC at PC's 7/20/04 meeting in Vancouver. The Drafting Team is responding to all comments submitted on these SARs, and will review and consider

		the comments submitted by the IDWG that you referenced.
Kathleen Goodman	ISO NE	For periodic testing of generator capabilities, it could be problematic to determine how to consistently conduct tests. In addition, there are difficult financial issues to be dealt with. The group should also consider the resource requirements to test and audit compliance. It would be beneficial to survey the industry to determine the level of current testing. This would provide some idea of the additional resources and implementation time for these new requirements. Based on previous experience, determination of dynamic load modeling will be a challenge. It is not clear why the System Restoration standards (IV.B….) are being included in this process. The importance of these particular standards does not seem to warrant fast tracking rather than going through normal due process. Version 0 already has requirements for restoration plans, so any standards developed here should be coordinated with existing Version 0 standards (EOP-005, R7 and R8) to assure consistency and, perhaps, even included in the existing Standards through a Version 1 iteration. The SARS indicate that the resultant Standards are developed and approved in groups or "batches." Although the development of the Standards can be done in groups we suggest "individual ballots" for the resulting Standards. In translating the Planning Measures into Reliability Standards, the Drafting Team eliminated the references to generator testing. As you've suggested, this is just one method of verifying models and data, and not the only valid method. The proposed Standards require that models and data be verified, but don't specify 'how'. While the objectives of the III.E.M1 through M3 (address dynamic load modeling) standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available. All of the Planning Measures, (including IVB that addresses Automatic Load Restoration Programs) that were dropped from the V0 Standards are included in this set of SARs. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.

		No decision has been made on how to ballot the proposed Standards.
Allan Adamson	New York State Reliability Council (NYSRC)	The drafting teams have been tasked to recommend whether the Phase III-IV standards should be balloted individually or in groupings. We suggest that each standard to individually balloted, as is done with other proposed standards. If instead the standards were balloted in groups, a problem with one or two standards could result in a NO vote on the entire group. Each proposed Phase III-IV standard should reference related Version 0 standards. No decision has been made on how to ballot the proposed Standards. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc. Building a reference table as suggested is a large effort and it isn't clear how this would advance the development of these new standards.
Guy Zito	NPCC	Blackstart Capability SAR; 1. NPCC participating members fully support the need to develop the remaining planning standards regarding black-start (IV.A.M2 and M3) in this SAR group to complement the 2 (IV.A.M1 & M4) translated in version 0 (EOP-007 & EOP-009). 2. It should be stressed that these 2 black-start standards must be developed with due consideration of the version 0 standard EOP-005 "System Restoration Plan" R7 and R8 to ensure consistency, eliminate duplication and incorporated as additional requirements to standard EOP-005. In other words these 2 black-start planning standards should form part of the overall system restoration plan. 3. In translating these particular standards, there may be a need to expand this SAR to include the Version 0 existing planning standards associated with Restoration and Blackstart during the open comment process since they have never been fully field tested and to capture issues of physical security regarding the diagrams identifying locations of Black-start facilities. 4. NPCC questions the emphasis being placed on the development of the Automatic Load Restoration standards (IV.B.M1-M4), for May 2005. These particular Phase IV standards have never been field tested and will require more time than is being afforded to appropriately develop. In addition NPCC does not employ automatic load restoration. Several of the SAR groups have standards that could be better severed as separate SARs to align with the version 0 standards already developed. As an example III.C.M1 to M4 (part of modeling SAR) address

		standards to maintain reactive resources and voltage level and are related to Version 0 standard VAR-001. These could be grouped as a separate SAR to ensure consistency, eliminate duplication and incorporated as additional requirements to standard Version 0 standard VAR-001. General Comment; Different standards of related measures currently appear under different SARs. The SARS indicate that the resultant Standards are developed and approved in groups or "batches". Although the development of the Standards can be done in groups we suggest "individual ballots" for the resulting Standards. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc. No decision has been made on how to ballot the proposed Standards.
Karl Tammar	ISO/RTO Council	For periodic testing of generator capabilities, it could be problematic to determine how to consistently conduct tests. In addition, there are difficult financial issues to be dealt with. In translating the Planning Measures into Reliability Standards, the Drafting Team eliminated the references to generator testing. As you've suggested, this is just one method of verifying models and data, and not the only valid method. The proposed Standards require that models and data be verified, but don't specify 'how'. Based on previous experience, determination of dynamic load modeling will be a challenge. While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available. It is not clear why the System Restoration standards (IV.B….) are being pushed through this process. The importance of these particular standards does not seem to warrant fast tracking rather than going through normal due process. Version 0 already has requirements for restoration plans, so any standards developed here should be coordinated with existing Version 0 standards (EOP-005, R7 and R8) to assure consistency.

		All of the Planning Measures, (including the IVB Measures that address Automatic Load Restoration Programs) that were dropped from the V0 Standards are included in this set of SARs. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.
Michael C. Calimano	NY Independent System Operator	For periodic testing of generator capabilities, it could be problematic to determine how to consistently conduct tests. In addition, there are difficult financial issues to be dealt with. The group should also consider the resource requirements to test and audit compliance. It would be beneficial to survey the industry to determine the level of current testing. This would provide some idea of the additional resources and implementation time for these new requirements. In translating the Planning Measures into Reliability Standards, the Drafting Team eliminated the references to generator testing. As you've suggested, this is just one method of verifying models and data, and not the only valid method. The proposed Standards require that models and data be verified, but don't specify 'how'. Based on previous experience, determination of dynamic load modeling will be a challenge. While the objectives of the III.E.M1 through M3 standards are important to grid reliability, the Drafting Team is recommending that these Measures be deleted because there is currently no accepted method of developing dynamic load characteristics of power system loads. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing standards now would not be effective since there would be no way to establish if the models provided were accurate and therefore these Measures are currently unenforceable. The Drafting Team recommends that a SAR be submitted once accurate and validated load models are available. It is not clear why the System Restoration standards (IV.B….) are being pushed through this process. The importance of these particular standards does not seem to warrant fast tracking rather than going through normal due process. Version 0 already has requirements for restoration plans, so any standards developed here should be coordinated with existing Version 0 standards (EOP-005, R7 and R8) to assure consistency. All of the Planning Measures, (including the IVB Measures for Automatic Load Restoration Programs) that were dropped from the V0 Standards are included in this set of SARs. Note that in the translation, the Drafting Team identified some Measures that are duplicates of already approved V0 Standards, and found several opportunities to add Measures to existing V0 Standards. Please see the summary table for more information about which Measures are being recommended for deletion, merging, etc.

		The SARS indicate that the resultant Standards are developed and approved in groups or "batches". Although the development of the Standards can be done in groups we suggest "individual ballots" for the resulting Standards. No decision has been made on how to ballot the proposed Standards.
Roman Carter	Southern Company	To have any Standard go through the SAR and Standard development process and be adopted by the Board in less than six months is almost an impossible task without being an Urgent Action Standard. To think that all the Standards contained in the Phase III/IV Planning Standards can go through the ANSI Standard Process and the NERC Process Manual procedures and be adopted in less than six months is even a larger (if that is possible) task to accomplish. We are concerned that errors and/or technically unsound requirements will occur. Additionally, if no field testing occurs or if Industry consensus is not reached may result in doing the wrong thing for the right reason and could result in increasing the chances for a system disturbance rather than preventing one. Unlike the standards included in the Version 0 effort, many of the key components in these Planning Standards that apply to generation have not been field tested. Due to the importance of these standards and their potentially significant impact on generating plant operation and safety, time should be allowed to work through the issues to produce standards that are practical, have a sound technical basis, and effectively contribute to improved system reliability. In translating the Planning Measures into Reliability Standards, the Drafting Team eliminated the references to generator testing. As you've suggested, this is just one method of verifying models and data, and not the only valid method. The proposed Standards require that models and data be verified, but don't specify 'how'. This is a monumental task, but is necessary to fill holes in the current standards. Many of these Measures have already been field tested and just lack minor modifications to reflect the findings from that field testing. Nuclear plants have formal Problem Investigation processes with defined time guidelines and manage their resources accordingly. In some cases, this process may allow for more than 30 days to complete investigations into causes of trips. NERC requirements should not impose unnecessary time requirements more restrictive than existing processes. The proposed Standard does include providing an analysis and mitigation plan within 30 days of a 'request' – the 30 days is not tied to the date of the misoperation 'event'.

Kirit S. Shah	NERC Transmission Issues Subcomittee (TIS)	TIS has no additional comments.
Lance Hall	Cinergy	
Tom Mielnik	MidAmerica Energy Company	
Peter Burke	American Transmission Company	
Brandon Snyder	Duke Energy	
John Mulhausen	Florida Power & Light Co.	
Ed Davis	Entergy Services	
Christopher Schaeffer	Duke Energy	
Doug Hils	Cinergy	
William J. Smith	Allegheny Power	
Gerald Rheault	Manitoba Hydro	
Marv Landauer	BPA	

Comments on Specific Standards — SAR Question 4 and Historic Comments.

This document contains the comments submitted in response to Question 4 of the Phase III & IV SAR Comment Form. Question 4 asked Stakeholders to comment on the challenges to achieving consensus in converting the Planning Measures to Reliability Standards.

Question 4: Challenges to Achieving Consensus
Some of the proposed standards may require more work than others to reach industry consensus on approving the standards. Please rate each proposed standard below by indicating the level of difficulty you foresee in achieving consensus on the standard. Please indicate specific challenges you think must be overcome to complete the standard and achieve industry consensus.

In addition to the comments submitted in response to Question 4 of the SAR Comment Form, the Drafting Team also considered comments previously submitted on this set of Phase III & IV Measures, including comments that were submitted in response to the first posting of Version 0 and comments that were submitted following the Field Testing of the Phase III Measures. The Phase IV Measures were not Field Tested.

Contents:

ID – Voltage Support and Reactive Power

Summary Consideration:

There are two Measures in this series – IDM1 and IDM2.

- IDM1 was modified and translated into Reliability Standard VAR-003-1 (Assessment of Reactive Power Resources).
- IDM2 was not translated because Stakeholders indicated the Measure was a duplication of already approved V0 Standards.

V0 Comments on Multiple Measures:

Mike Gildea - Constellation

THIS HAS NOT BEEN FIELD TESTED PRIOR TO SUCH AN WIDE SCALE MPLEMENTATION. ADDITIONALLY, LANGUAGE IS NEEDED IN THIS STANDARD THAT EXPLICITLY REQUIRES COMPARABLE TESTING REQURIEMENTS AS WELL AS COMPARABLE SCHEDULING OF TESTING REQUIREMENTS FOR ALL GENERATION IN THE REGION

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

The intent of these standards was to ensure that the Transmission Planner and Planning Authority have accurate data needed for models and assessments. Testing was not required in the proposed Standards as it may not be the only effective method for ensuring accuracy of data.

FRCC and Bryan Guy - Progress

Applicability - Needs to be expanded to include Load Serving Entities, to ensure that they have adequately planned for power factor correction in accordance with the Transmission Owner's published standard.

This should not be applicable to LSEs because this Standard is addressing assessments which are the responsibility of the Planning Authority and the Transmission Planner.

Agree that the LSEs need to contribute data for reactive capability assessments, but the responsibility for having a methodology for conducting these assessments and the responsibility for conducting the assessments, rests with the PA and TP.

Charles Matessa - BG&E

Concern: An organization can meet the requirements identified yet not come close to the depth and breadth of the study requirements mandated by FERC/DOE to First Energy following the blackout. A reactive adequacy study for major load centers should be part of this standard with a requirement that it be performed at least once every three years. There is just too great a dichotomy between the standard and the study required of First Energy.

The Drafting Team expanded the Standard to include a requirement that the Planning Authority and Transmission Planner each have a methodology and criteria for assessing adequate static and dynamic reactive power requirements

ID M1 - Assessment of reactive power resources

Summary Consideration:

IDM1 (Adequate Voltage Resources to Meet Future Customer Demands) was modified and translated into a new Standard VAR-003-1 (Assessment of Reactive Power Resources).

Many Stakeholders commented that this Measure should not be moved forward because it is already covered in TPL-001-0, TPL-002-0, and TPL-003-0. The Drafting Team was concerned that while similar requirements are contained in the already approved TPL-001-0, TPL-002-0, and TPL-003-0 Standards, these V0 Standards do not require that there be a documented methodology and criteria for assessing reactive capabilities. The Blackout Report highlighted a need to pay particular attention to reactive resources. The Drafting Team added a requirement that the Planning Authority and Transmission Planner have a methodology and criteria for assessing adequate static and dynamic reactive power requirements. The Drafting Team will ask the Stakeholders if they agree with the new requirement and with keeping this Measure in the set of Standards being moved forward for approval.

V0 Comments on M1:
Travis Bessier - TXU

This Section appears to be unnecessary, since it is covered by Standard 051.

Please see the summary consideration.

Bob Millard – MAIN

This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 051. Not well defined and/or detailed, needs further drafting for implementation. Consideration should be given to incorporating this into STD 051 for added emphasis.

Please see the summary consideration.

MAPP Planning Standards Subcommittee

R1-3 is redundant, it does not contain any thing different that what is in R1-1.

Agree. Both R1-1 and R1-3 in the first draft of the V0 posting indicated that the assessment needed to be conducted at least once every 5 years. In the proposed Standard, this redundancy has been eliminated.

Robert Snow

A considerable amount of reactive power compensation must occur at the distribution level. There need to be a requirement on the LSE and DP to coordinate with the TP at the very lease. The existing language applied to the interface between transmission and distribution.

Agree that the LSEs and DPs need to contribute data for reactive capability assessments, but the responsibility for having a methodology for conducting these assessments and the responsibility for conducting the assessments rests with the PA and TP.

Pete Henderson – IMO and Guy Zito - NPCC

std 064 Section 1 -Requirements (M1-4): Need to clarify whether 30 days or 30 business days.

Agree. All of the V0 Planning Standards were modified to indicate that the turnaround time for providing documentation would be either 'five business days' or '30 calendar days'. These default time periods have been adopted for use with Version 1 Planning Standards.

SAR Comments on M1:
Tom Mielnik; MidAmerican Energy

This standard should be field tested first.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

What guidelines are used for making sure static and dynamic are balanced? How will it be decided if a new assessment is warranted by system conditions. Some regions may look at system conditions and make the call that new assessments are not required when other regions may say it does require a new assessment. Will there be consistency measurements for making this decision?

The proposed standard requires that the assessment be conducted to determine if there is 'adequate static and dynamic reactive power' – the proposed standard does not require that the assessment show that static and dynamic reactive power are 'balanced'.

The phrase, 'or as required by changes in system conditions' was used in original Planning Standards and was carried over into the V0 Planning Standards. This has not posed a recognized problem up to now.

This Standard should be field tested before being adopted.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Kathleen Goodman; ISO-NE (Peter Henderson; IESO) (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO)

Implies that a separate reactive assessment must be made, but it is possible, and probably better, to do reactive assessment in the "I.A" assessments

Please see the summary consideration.

Doug Hils; Cinergy; Lance Hall; Cinergy (Generators)

If you meet Table I.A as required in this standard then why do you need a separate standard? Based on the wording of this standard there are no new requirements above I.A so delete this standard.

Please see the summary consideration.

Alan Adamson; NYSRC

Development of this standard and the next one should recognize and be coordinated with the Version 0 VAR standards.

Agree. This Standard is complementary to Version 0 Standards.

Peter Burke; ATC

May be better addressed by enhancing I.A. standards; please see comments to Q.2.

Please see the summary consideration.

Brandon Snyder; Duke Energy

The concern would be the 5yr repeat requirement.

The Drafting Team is not sure what your concern is and, therefore, cannot provide a response.

Transmission Issues Subcommittee(?)

As commented in response to Question 2, I.D.S1.M1 is redundant and should be eliminated. The guidelines are useful and should be incorporated in other standards.

Please see the response to Question 2, IDS1M1.

Comments Submitted During Development of Standard on M1

SERC

Recommend that this measurement be deleted as a stand-alone template, and that all the I.D Guides be moved to the IA Standards.

Please see the summary consideration.

ID M2 - Generator Reactive Power Capability

Summary Consideration:

IDM2 (Coordinate and Optimize the Use of Generator Reactive Capability) was not translated into a new Standard and the Drafting Team did not attempt to provide responses to individual comments. Stakeholder comments indicated that the language in the source Measure was vague and unmeasurable, and the intent of the source Measure is duplicated in already approved V0 Standards or in other proposed Standards. For these reasons, many Stakeholders indicated that this Measure should not move forward and the Drafting Team is recommending that this Standard be removed from the set of Standards moving forward for approval. The Drafting Team will ask Stakeholders if they agree with this deletion.

V0 Comments on M2

Bob Millard - MAIN

This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 051. Not well defined and/or detailed, needs further drafting for implementation.

MAPP Planning Standards Subcommittee

R1-3 R1-3 is redundant, it does not contain any thing different that what is in R1-1.

Pete Henderson – IMO and Guy Zito - NPCC

std 064 Section 1 -Requirements (M1-4): Need to clarify whether 30 days or 30 business days.

Travis Bessier - TXU

It is not clear whether the coordination demonstration required by this Section must be on a generating unit basis or on a generation owner basis. In an electric market, with unbundled entities, the Transmission Operator can optimize reactive power use only to the degree allowed by the Generation Owner's unit and auxiliary equipment design.

Similarly, system reactive needs and optimization will depend upon uses of generation that are beyond the control of and the forecasting ability of the Transmission Operator.

SAR Comments on M2

Tom Mielnik; MidAmerican Energy

This standard should be field tested first.

Raj Rana; AEP

transmission owners and generation owners likely have different perspectives of "optimum"

Karl A Bryan; US Army Corps of Engineers - Generators

Getting competent personnel that can consistently measure the modelling parameter is one of the hurdles, the other is getting the system configured so that the testing can be performed.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC) (Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE))

Recommend changes to the measure:

ENSURE MAXIMUM FLEXIBILITY rather than OPTIMIZE THE USE of generator reactive power capability. Also AGREEMENT ON rather than ENSURING FULL range of reactive power is available.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

Ensuring full range reactive power capability under emergency voltage ranges will be hard to define. Voltage vs. duration curves would need to be agreed upon, potentially causing issues.

Ed Davis; Entergy Services

Applicability should be changed to the Planning Authority.

Peter Burke; ATC

Capability information may not be available for older and smaller units.

Transmission Issues Subcommittee(?)

I.D.S1.M2 is ambiguous. Again, if the compliance test is satisfactory performance under categories A, B, and C of Standard I.A, then I.D.S1.M2 is not required. The guidelines are useful and should be incorporated in other standards.

Kathleen Goodman; ISO-NE; John Horakh; MAAC; ISO/RTO Council (9); Michael Calimano; NYISO; Peter Henderson; IESO

Coordination of the use of generator reactive capability can be measured, very difficult to measure if completely "optimized"

Doug Hils; Cinergy; Lance Hall; Cinergy (Generators)

This standard appears vague and would be hard to measure. How do you measure "optimize"? The II.B standards on testing and verification of generator data and the III.C standards on procedures for reporting data already cover getting the required data.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

The acceptable methods by which the full range reactive capability of the generator is made known should be made clear up front. Current methodologies should continue to be accepted. Recommend changes to the measure: ENSURE MAXIMUM FLEXIBILITY rather than OPTIMIZE THE USE of generator reactive power capability. Also AGREEMENT ON rather than ENSURING FULL range of reactive power is available.
This Standard should be field tested before being adopted.

Comments Submitted During Development of Standard on M2

SERC

Recommend that the concepts of I.D.S1.M2 be changed to a Guide in the I.C Standards on Facility Connection Requirements. If the measure remains, recommended revisions as listed below.

M2. Generation owners and transmission providers shall work jointly to ensure maximum flexibility ~~optimize the use~~ of generator reactive power capability. These joint efforts shall include:

a. Coordination of generator step-up transformer impedance and tap specifications and settings,
b. Calculation of underexcited limits based on machine thermal and stability considerations, and
c. ~~Ensuring that~~ Agreement on the ~~full~~ range of generator reactive power capability that is available for applicable normal and emergency network voltage ranges.

IF – Disturbance Monitoring

Summary Consideration:

There are four Measures in this Series – IFM2, IFM3, IFM4, and IFM5.

IFM2 (Disturbance Monitoring Equipment List) and IFM4 (Disturbance Data) were merged and translated into a new Standard, PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting).

IFM3 (Disturbance Monitoring Data Reporting Requirements) was merged into the existing already approved V0 Standard, PRC-002-1(Define and Document Regional Disturbance Monitoring and Reporting Requirements).

IFM5 (Use of Disturbance Data to Develop and Maintain Models) was translated into a new Standard, MOD-022-1 (Use of Disturbance Data to Develop and Maintain Models).

Comments Submitted During Development of Standard on Multiple Measures

ECAR

I F, Standards 1 & 2, Measurements 2 & 3

Measurements 2 and 3 do not seem to support the associated Standards. For example, Measurement 3 under Standard 2 is requesting disturbance information from the monitors be collected in order to "develop, maintain, and update transmission system models." But the primary purpose for this data should be to analyze what happened on the system when a disturbance occurs and determine its cause, which is stated in Standard 1. ECAR recommends that the wording from Standard 2 "and for the purpose of developing, maintaining, and updating transmission system models" be added to Standard 1 after "…causes of system disturbances…" and that Measurement 2 and 3 be listed under Standard 1 to support it. Standard 2 can then be deleted. Both Measurements 2 and 3 support analyzing system disturbances and updating transmission models.

The purpose statements were developed to clarify the intent of the proposed Standards. The sequence within the purpose statement was revised as recommended. Standard 2 was merged with Standard 1.

I F, Measurements 2, 3, 4; III E, M 1, 4 & 5; IV B, M4

There seems to be a conflict between the last sentence in the Measurements and the compliance Monitoring Responsibility. The last sentence of the Measurements states "…shall be provided to the appropriate Regions and NERC…"; whereas the Compliance Monitoring Responsibility for these Templates applies to either NERC OR the Regions, depending upon the Template. It seems the Compliance Monitoring Responsibility should apply to BOTH NERC AND the Regions, if this is the case. If the compliance Monitoring Responsibility falls to the Regions, then the Measurements should not mention NERC.

The proposed Standards reflect the hierarchy of NERC making requests of Regional Reliability Organizations (RROs), and RROs making requests of entities that report to that RRO. The Compliance Monitor for the RRO has been changed to NERC – and the RRO is the Compliance Monitor for entities that report to that RRO.

IF M2 - List of monitoring equipment installations & operating status

Summary Consideration:

IFM2 (Disturbance Monitoring Equipment List) was modified and translated with IFM4 (Disturbance Monitoring Equipment Installation and Data Reporting) into Standard PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting). The proposed Standard supports the intent of both of the original Measures which is to ensure that system events are recorded for event analysis and the facilitation of model development. Most of the details of the original IFM2 were translated without significant change. The following changes were made to the original IFM2:

- Added language to require that the status of time synchronization equipment be part of the operational status that must be reported upon request
- Time period for reporting data was changed from 30 'business' days to 30 'calendar' days to improve consistency between standards.
- Modified the levels of non-compliance to eliminate gaps that were identified during Field Testing

V0 Comments on M2

Bob Millard – Main

This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

Most Stakeholders indicated this should move forward as a Standard.

Ameren

R2-1 goes further than the existing standard I.F. by requiring the installation of disturbance monitors per regional requirements. We disagree that the guides section should be eliminated. These guides contain many critical items as stated in the black-out recommendations, such as the need for time synchronization and coordination with neighboring regions.

The last approved version of Planning Standard (IFM2) did include the following which was evenly translated for V0 and for the proposed Standard:

Regional members, generation owners, and transmission owners shall install disturbance monitoring equipment to meet the Regional requirements determined in I.F. S1, M1.

Elimination of Guides was addressed during the development of V0 Standards.

The Standard was revised to clarify that the time synchronization status is part of the operational status that must be reported.

MAPP Planning Standards Subcommittee

M2-3 should be added to match up with Requirement R2-3? This Measurement could read as "The Transmission Owner and Generator Owner shall have evidence it provided current data on its disturbance monitoring equipment installations in accordance with Standard 057-R2-3." Measurements should align with the Requirements of a Standard and not the Levels of Non-Compliance.

It is acceptable to have a single measure that addresses more than one requirement.

SAR Comments on M2

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

Agree. The Drafting Team has considered all comments, including those from field testing, in developing the draft standards.

Raj Rana; AEP

Listing of equipment should not be a major hurdle.

Agree.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE) and Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

The Regions should be very clear in specifying the type of data being required.

The Standard allows each Regional Reliability Organization to specify what it needs.

John Mulhausen; FP&L

Item 4 requires a list of all quantities monitored. Compiling the list is highly labor intensive and adds no value. Likewise, the standard should not establish maintenance requirements at the channel level but only at the equipment or machine level.

This has been revised as follows:

1. Monitored facilities (lines, buses, etc.) and ~~associated~~ monitored quantities (MW, Mvar, etc.)

The 'list' of the monitored facilities and monitored quantities is typically available in some format and shouldn't require any significant additional work.

The proposed Standard does not establish maintenance requirements at the channel level – operational status should be interpreted as 'is it working'.

Comments Submitted During Development of Standard on M2

WECC

I.F.S1.M2 (Disturbance Monitoring Equipment) – It is unclear from the current levels of non-compliance what level an entity would be if they have all disturbance monitoring equipment installed but the current data on the installations is incomplete and does not meet three or four or five of the six requirements listed. Suggest either modifying level 2 to include not meeting 2-5 of the requirements or add a level 3 for not meeting 3-5 of the requirements.

Please see the summary consideration. The levels of non-compliance were modified so there are no 'gaps'.

IF M3 - Disturbance monitoring data reporting Requirements

Summary Consideration:

IFM3 (Disturbance Monitoring Data Reporting Requirements) was modified and merged into already approved V0 Standard PRC-002-1 (Define and Document Regional Disturbance Monitoring and Reporting Requirements).

The requirement to include a definition of disturbance which was in the original IFM3 Standard was omitted from the proposed PRC-002-1 Standard because NERC adopted a V0 definition of 'Disturbance' that must be used for all NERC Reliability Standards. The following two new elements were added to the list of elements that must be addressed in the Regional Reliability Organization's data reporting requirements:

- Criteria for determining which Disturbance data shall be reported and when the data shall be submitted.
- List of entities that must be provided the Disturbance data

These changes will close the 'gaps' identified during the drafting of this set of Standards.

V0 Comments on M3

Bob Millard – Main

This section should not move forward in Version 0. More procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard

Most Stakeholders indicated this should move forward as a standard**.** The requirements were merged so it is not a stand – alone standard.

Ed Davis Entergy

Reactive Capability curves? (See Std 59 R3-1)

Overall Applicability Section 3 should be appropriate entity according to the Functional Model in place of Regional Reliability Councils and Section 5 should be Planning Authority, Transmission Planner, and Generator Owner

The Regional Reliability Organization (RRO) was retained even though it isn't in the Functional Model. Many of the requirements currently assigned to the RRO can't easily be assigned to any of the Functions in the Functional Model.

Charles Matessa - BG&E

Include Item 7. Point of Contact for delivery of required data.

This seems more specific than necessary.

MAPP Planning Standards Subcommittee

The use of the word "entities" seems very broad after the development of the NERC functional model. Is there some specific titles that can be assigned to entities within R3-1 that are included as part of the NERC functional model, such as "Generator Owner" and "Transmission Owner"?

Agree. The proposed Standards include the list of specific Functions and avoids use of the generic term, 'entities'.

The use of the word "Regional disturbance data reporting requirements" seems a bit repetitive since "Regional Reliability Council" had been used previously in the same sentence. The word "Regional" could be deleted in that reference to disturbance data reporting requirements.

Agree. The Standard was modified as suggested.

Ed Davis Entergy

R3-2 references 5 business day requirement while Section 3 Compliance says 30 business days

The proposed Standard uses '5 business days'.

NIPSCO

The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

The phrase, 'shall have evidence' is intended to give entities as much flexibility as possible in verifying that they are compliant. If the Drafting Team included language that was more specific, such as requiring that the evidence by a Fed Ex receipt, then an entity that use e-mail to distribute its reporting requirements would need to change its existing process and begin using Fed Ex, and this would require additional resources without any additional improvement to reliability.

SAR Comment s on M3

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft standards.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

The Regions should be very clear in specifying the type of data being required.

The Standard allows each Regional Reliability Organization to specify what it needs.

Ray Morella; FirstEnergy

The use of the term disturbance monitoring needs to be used consistently. For example, ECAR uses the term disturbance monitoring as an umbrella covering fault monitoring, sequence of events monitoring, and long-term disturbance monitoring. Many people in the industry use the term disturbance monitoring to imply only long-term disturbance monitoring. The SAR and the standards produced as a result of the SAR need to clearly define these terms.

Agree. With V0, the term, 'disturbance' was defined and the Drafting Team tried to use it consistently throughout the set of Standards. In addition, the Drafting Team added a definition for Disturbance Monitoring Equipment.

IF M4 - Recorded fault and disturbance data

Summary Consideration:

IFM4 (Disturbance Data) was modified and translated with IFM2 (List of monitoring equipment installations & operating status) into Standard PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting). The proposed Standard supports the intent of both of the original Measures which was to ensure that system events are recorded for event analysis and the facilitation of model development.

The original IFM4 requirements and measures were translated with only one significant change – there is no longer a requirement to provide the data to NERC upon request. The Standard requires that data be provided to the Regional Reliability Organization as required in the associated Standard, PRC-002-1(Define and Document Regional Disturbance Monitoring and Reporting Requirements). In PRC-002-1, each Regional Reliability Organization is required to document its Disturbance data reporting requirements. NERC is not the Compliance Monitor for this Standard. If NERC needs data, NERC should get the data from the Regions.

V0 Comments on M4

Consumers

> The requirement in this draft suggests that all disturbance data shall be provided to the RRC on request, and would result in the reporting of several years of data for all available recording equipment. Please change this requirement to indicate "all relevant data" or "all data as specified by the RRO".

The Drafting Team was not able to associate this comment with IFM4

NIPSCO

> The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

The Drafting Team was not able to associate this comment with IFM4

SAR Comments on M4

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE) and Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

> The Regions should be very clear in specifying the type of data being required.

The Standard allows each Regional Reliability Organization to specify what it needs.

Brandon Snyder; Duke Energy

> The amount of work cannot be completed with in one year

Please be more specific in identifying what part of the Standard you feel can't be met within a year.

Tom Mielnik; MidAmerican Energy

> Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft standards.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (Michael Calimano; NYISO) (ISO/RTO Council (9))

> Applicable To entities may feel they could be suject to unreasonable Regional requirements for providing disturbance data

Entities who feel that the requirements are unreasonable may use the Dispute Resolution Process.

Ray Morella; FirstEnergy

> The use of the term disturbance data needs to be used consistently. What data is required to be recorded? How will the data be captured - continuously or event triggered?

The Standard allows each Regional Reliability Organization to specify what it needs.

Comments Submitted During Development of Standard on M4:

ECAR

I F, Measurement 4

Under "Timeframe", delete the second sentence "Current data on request (30 business days)". REASON: This statement creates a conflict as to when data is due to be submitted to the Regions. For example, if the Regional document states 45 days and this Template states 30 business days, what is the due date for the entity submitting the data? Which document takes precedence?

Please see the summary consideration.

IF M5 – Use Database

Summary Consideration:

IFM5 (Use of Disturbance Data to Develop and Maintain Models) was modified and translated into MOD-022-1 (Use of Disturbance Data to Develop and Maintain Models). The Standard was modified to focus on the intent – which was to use data from disturbances to verify or improve the accuracy of models. This Standard will improve system assessments which will, in turn, improve the reliability of the grid.

The original IFM5 requirements and measures were translated with the following significant changes:

- The Standard was modified to focus on the intent – which was to use data from disturbances to verify or improve the accuracy of models.
- Language requiring improvements to steady-state and dynamic system models and generator performance models was changed to only address steady-state and dynamic system models. Language addressing generator performance models was dropped from the proposed Standard.
- The Standard requires use of 'data' rather than use of a 'database'.

V0 Comments on M5

Bob Millard – MAIN

This section should not move forward in Version 0. Not well defined and/or detailed, needs further drafting for implementation

Most Stakeholders indicated this should move forward as a standard.

Raj Rana – AEP

Delete proposed Measure; not measurable.

The Standard was modified to make it more measurable.

SAR Comments on M5

Lance Hall; Cinergy (Generators) (Doug Hils; Cinergy)

do we really need a standard to force entities to make use of a database? Recommend eliminating this standard

Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

The measure is not suitable for a standard because it requires regional members to "use recorded data" when, in fact, what is required is "use of recorded data" which results in "improved" models, etc. But how can that be meaningfully measured? MidAmerican recommends a major change in the standard or else deleting it altogether.

Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

There is a lack of clarity concerning enhancement of steady state models in reference to disturbance data. It may be impractical for the region to maintain this database and is not needed since the data is maintained and available from members.

Please see the summary consideration.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

There are many questions and issues around Digital Disturbance Recorder (DDR) locations and how to use the data. Industry approval will depend on how much lattitude regional members will have. Does the Standard specifically allow other data sources (that are not DDR)?
This Standard should be field tested before being adopted.

The Drafting Team has proposed a definition for 'Disturbance Monitoring Equipment' which should clarify that many different devices qualify as 'Disturbance Monitoring Equipment'.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Ed Davis; Entergy Services

> Mostly a duplicate of M4, to provide disturbance data to the Region as defined by the Region.
> Could be pared down to only require Region to maintain a database of the data.
> Would be better to simply eliminate the requirement.

Please see the summary consideration.

Raj Rana; AEP

> the Measure is unmeasurable and should not be translated to a Version 0 Standard

The Standard was modified to make it more measurable.

Brandon Snyder; Duke Energy

> There are many questions and issues around DDR locations and how to use the data. If there is great latitude on how much of this we do, then approve. This also doesn't specifically allow other data souces (that are not DDR).

The Drafting Team has proposed a definition for 'Disturbance Monitoring Equipment' which should clarify that many different devices qualify as 'Disturbance Monitoring Equipment'.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

> It may not be practical for the regions to maintain this database and is not needed since the data is maintained and available from members.

Please see the summary consideration.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO)

> Compliance should not be measured only by whether or not changes to models were made.

The intent of your comment is supported in the revised measures and compliance levels.

Ray Morella; FirstEnergy

> In the detailed description section there is a reference to planning standard IFS2M5. It is not clear what is meant by "Use database" and which data is involved.

The cross references have been updated and references to the database were removed.

Comments Submitted During Development of Standard on M5

SERC

> It is not clear what is meant by the enhancement of steady state models in reference to disturbance data. Recommend that this measurement be made a guide. If that is not acceptable, recommend that the measurement be revised as follows to require region members to document and implement a process to review recorded data from disturbance monitoring equipment to verify or modify (as needed) dynamic system models and generator performance models.
>
> > M5 (was M6). Regional members shall document and implement a process to review recorded data from disturbance monitoring equipment to verify or modify (as needed) dynamic system models and generator performance models.

The set of Standards was modified to require the Regional Reliability Organization to establish criteria for use of recorded disturbance data to verify or improve system models. A fault model is an example of a steady state model that could be improved through the use of disturbance data (e.g., data from a DFR).

IIB – Generation Equipment

Summary Consideration:

There are six Measures in this Series – IIBM1, IIBM2, IIBM3, IIBM4, IIBM5, and IIBM6.

IIBM1 (Regional procedures for generation equipment testing) was translated into a new Standard, MOD-023-1 (Procedures for Verifying Generation Equipment Data).

IIBM2 (Verification of gross and net real power dependable capability of generators) was translated into a new Standard, MOD-024-1, (Verification of Generator Gross and Net Dependable Capability).

IIBM3 (Verification of gross and net reactive power capability of generators) was translated into a new Standard, MOD-025-1, (Verification of Reactive Power Capability).

IIBM4 (Test results of generator voltage regulator controls and limit functions) was merged with IIBM6 (Verification of excitation system dynamic modeling data) into a new Standard, MOD-026-1 (Verification and Modeling of Generator Excitation Systems and Voltage Controls).

Comments Submitted During Development of Standard on Multiple Measures

SERC

II.B.S1.M2, M3, M4, and M5

The regional procedure required in II.B.S1.M1 should contain the detail data requirements currently listed in measurements M2, M3, M4, and M5. Accordingly revisions are recommended below to each of these measurements to eliminate detail data requirements by adding "in accordance with regional requirements as defined by II.B.S1.M1." Another common revision recommended to these measurements is to de-emphasize testing requirements to allow for other methods of data validation.

Please see the Drafting Team's consideration of the individual comments.

V0 Comments on Multiple Measures

Tom Mielnik – MidAmerican

MEC is concerned with the extraordinary cost and effort that is required by this standard for generator testing. MEC urges the Drafting Team or NERC to pick out a few parameters that are relatively easy and safe to test for and that are clearly needed for system reliability and leave the rest of this standard as a guide.

Agree. The Standard was revised so that testing is just one of the acceptable methods verification of generator modeling and equipment data.

Robert Snow

The stated purpose of this standard is to validate generator modeling data with reall data. There are a number of ways to obtain the data and all approaches should be considered acceptable.

Agree. The Standard was revised so that testing is just one of the acceptable methods of verifying generator modeling and equipment data.

IIB M1 – Procedures for validating generation equipment data

Summary Consideration:

IIBM1 (Regional procedures for generation equipment testing) was modified and translated into a new Standard, MOD-023-1 (Procedures for Verifying Generation Equipment Data). The proposed Standard supports the intent of the original Measure which was to ensure that generator models and data are accurate, while removing the requirement that generator testing be used to validate generator models and data.

Many Stakeholders indicated that generator testing is not the only method for validating generator models and data. The proposed Standard requires Regional Reliability Organizations (RROs) to establish and maintain procedures to address verification of generator modeling and equipment data.

- MOD-023-1 requires each RRO to document its procedures for verification of generator models and equipment data.
  - MOD-023-1_R1.1 requires the RRO to identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the RRO's model and verification procedures.
  - MOD-023-1_R1.2 requires the RRO's procedures to identify that **a**cceptable methods for model and data verification include but are not limited to manufacturer data, performance tracking, simulation, analysis and testing.
  - MOD-023-1_R1.3 requires the RRO to identify the periodicity and schedule of model and data verification.

Conforming changes were made to the proposed Standards that require Generator Owners to validate their models and data.

Collectively, the proposed Standards address most of the Stakeholder concerns and should be more acceptable than their associated source Measures.

V0 Comments on M1

Raj Rana – AEP

Presumably. the 'reporting parties' are the entities within the region required to provide data. If so, clarity on who the 'reporting parties' are would be beneficial.

The revised proposed Standard does not use the phrase, 'reporting parties'.

Ed Davis Entergy

Section 1, M1-2 states that "the Regional Reliability council shall have evidence it provided documentation of its procedures. . ." Do we really need a requirement stating that they be able to provide evidence that they provided information?

This is a 'fairness' requirement designed to ensure that the procedures are provided to the Generator Owners.

SAR Comments on M1

Christopher Schaeffer; Duke Energy and Brandon Snyder; Duke Energy

In general, the II.B requirements have not been through a due process, so a translation to the new format without evaluating previously developed concerns is inappropriate. The SERC GS members have agreed to the guidelines developed in the SERC IIB Supplement, which was developed in response to the planning standards to develop a consensus approach to address generator model validation and there will likely not be significant resistance in by the SERC generation operators, as long as the new language in the NERC requirement does not invalidate the processes developed in the SERC supplement. Significant differences will likely require the SERC Generator Model Validation task force to be reestablished to address.

The Phase III/IV Planning Standards have undergone some portion of a standards review process. Please see the summary consideration.

Lance Hall; Cinergy (Generators)

Will require tests that are not routinely done today which will impose a cost every five years

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

Procedures for providing the information is easily developed but actual data is difficult to acquire. Agreed upon methods may provide issues.

Please see the summary consideration.

Comments Submitted During Development of Standard on M1

SERC

II.B.S1.M1

Recommend the following revisions be made.

M1. Each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net ~~dependable~~ real power (MW) capability, reactive power capability, ~~voltage regulator controls,~~ speed/load governor controls, generator characteristics, and voltage regulator and excitation control systems ~~and excitation systems~~ (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures.

The word “dependable” is deleted from the text because it confuses the meaning of the statement considering the connotations associated with past uses of the word.

The word, ‘dependable’ was replaced with ‘real power (MW) as suggested.

SAR Comments on M1

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

"Dependable capability" should be changed to "real power capability". The connotation of the the word "dependable" confuses the meaning of the statement. "Voltage regulator controls" and "excitation systems" should be combined to state "voltage regulator and excitation control systems". The required regional procedures shall also cover "generator characteristics".

The word, ‘dependable’ was replaced with ‘real power (MW) as suggested.

Agree that voltage regulator controls and excitation systems should be combined into a single element.

Karl A Bryan; US Army Corps of Engineers - Generators

Recommend the procedures be more performance based. You do not want to try and cover all the possible equipment types in a cook book type of testing document. Also, there should be a certification process for those that are gathering the modeling data.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Addressing the certification of personnel is outside the scope of this set of Standards.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Allow Regional procedures to vary. Allow exemptions to be made by type of generator, not just by individual unit

Please see the summary consideration. Each Regional Reliability Organization is required to develop its own procedures for model and data verification.

Raj Rana; AEP

Probable disagreement on equipment that needs testing for reliability purposes

Please see the summary consideration. Each Regional Reliability Organization 's procedure for model and data verification must identify generating unit exemption criteria

Gerald Rheault; Manitoba Hydro

The cost implication for this item is a concerm for many entities.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.
These changes should help keep the costs associated with compliance as low as practical while still protecting reliability.

Peter Burke; ATC

May be costly and time consuming if testing is being considered.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first. Realistic testing requirements for "gross and net reactive power capability, voltage regulatory controls, speed/load governor controls, and excitation systems" needs to be fleshed out before this standard is adopted. Five business days is not an appropriate response time. In addition, prior to putting it into practice, this standard should be field tested first. Perhaps a qualification that "if safety or system conditions warrant, computations and engineering reports shall be provided in lieu of testing" will help get this standard approved.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.
Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

The scope of generating standards within the II.B category should be limited to those that are already being addressed at the regional level in response to the Blackout recommondations. It is important to note that the II.B standards have not been through a proper development and field testing process to achieve industry consensus. This may be difficult due to the nature of the standards and measurements as currently written. The potential impacts of some of the proposed testing on generating plants have not been fully threshed out, and there are concerns that compliance with portions of these standards could impact safety, equipment, or regulatory requirements. Furthermore, much industry experience has been gained in these areas by some regions, and their lessons learned need to be factored into the procedures for validating generation equipment data. Development of these standards should not be expedited at the expense of creating other problems or issues that could result in unnecessary tripping or even damage to generating plant equipment.

The Phase III/IV Planning Standards have undergone some portion of a standards review process. The comments from that review process have been considered in the development of the proposed Standard.

The proposed Standard does not require annual testing – the periodicity for verification is up to the Regional Reliability Organization to specify.

IIB M2 – Verification of gross & net dependable capability

Summary Consideration:

IIBM2 (Verification of Gross and Net Real Power Dependable Capability of Generators) was revised and translated into a new Standard, MOD-024-1 (Verification of Generator Gross and Net Dependable Capability).

The new Standard supports the intent of the original Measure which was to ensure generator gross and net real power capability are available and consistent with data used in models and assessments.

The original requirements to conduct generator testing were replaced with requirements for Generator Owners to 'verify' their data – the revised Requirements do not specify 'how' the Generator Owner must verify its data. Many Stakeholders indicated that generator testing is not the only method for verifying generator data and many Stakeholders indicated that re-validating data every five years may not be appropriate. The Proposed Standard requires Generator Owners to document their method of verifying generator data in a manner that meets the associated Regional Reliability Organization's (RRO's) requirements. The proposed Standard does not include any requirement that identifies the specificity for generator modeling and equipment data verifications. The proposed Standard does not require that verifications be accomplished each year – instead the RRO is free to identify the specificity for verifications.

Many of the Stakeholder concerns highlighted in the comments submitted on this Measure are addressed in the proposed MOD-023-1. In MOD-023-1, each RRO is required to document its procedures for verification of generator modeling and equipment data.
- MOD-023-1_R1.2 states that the RRO's procedures must identify that **a**cceptable methods for model and data verification include but are not limited to manufacturer data, performance tracking, simulation, analysis and testing.
- MOD-023-1_R1.3 requires the RRO to identify the periodicity and schedule of model and data verification.
- MOD-023-1_R1.1 requires the RRO to identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the RRO's model and verification procedures.

Collectively, the proposed Standards address most of the Stakeholder concerns and should be more acceptable than their associated source Measures.

V0 Comments on M2

FRCC

> Specific test requirements should be included in this standard that address; the "conditions" to be reported, whether max/min temperatures are to be stated, whether the generator summer and winter test can be completed at the same time and avoid a second annual test, and data be corrected for the conditions of the test.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. If a Regional Reliability Organization wants specific information to be provided, then the Regional Reliability Organization needs to include this in its Procedure for model and data verification.

Tom Brandish - Reliant

> Net and gross output verification should only be conducted one time each year during the peak season. If a second test is required by the region then a mechanism must be in place to reimburse the generator for conducting the second test. Otherwise, if output data is needed for a different time of the year the data from the peak season test should be used and temperature compensated for the period in question.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. If a Regional Reliability Organization (RRO) wants specific information to be provided, then the RRO needs to include this in its Procedure for model and data verification.
Cost recovery requirements are outside the scope of these Standards.

SAR Comments on M2

Christopher Schaeffer; Duke Energy (Brandon Snyder; Duke Energy)

No concerns as long as the SERC IIB supplement guidelines are used.

Without a copy of the SERC IIB supplement guidelines, the Drafting Team is unable to verify that the proposed Standard is in line with these guidelines.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first. Perhaps a qualification that "if safety or system conditions warrant, computations and engineering reports shall be provided" is appropriate.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Karl A Bryan; US Army Corps of Engineers - Generators

How are you going to handle environmental limitations, short term operational constraints, seasonal constraints, etc? I think you need to be very concise on what you ask for.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. If a Regional Reliability Organization (RRO) wants specific information to be provided, then the RRO needs to include this in its Procedure for model and data verification.

John Horakh; MAAC (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Allow operational data to be used instead of a separate test, if adequate

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

"Annually test to verify…" should be changed to "validate by appropriate means". What is the basis for annual updates versus three years, five years, etc. In addition to testing, other appropriate validation methods should be defined. Validation may be achieved through simulation, operating data, field verification readings, engineering evaluations or reviews, and/or testing where appropriate. Validation requirements shall also vary depending upon the size and type of generating unit.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The proposed Standard does not require annual testing – the periodicity for verification is up to the Regional Reliability Organization to specify.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

Required testing for two seasons annually will prove difficult to pass industry consensus. "Annually test to verify…" should be changed to "validate by appropriate means". What is the basis for annual updates versus three years, five years, etc.? In addition to testing, other appropriate validation methods should be defined. Validation may be achieved through simulation, operating data, field verification readings, engineering evaluations or reviews, and/or testing where appropriate. Validation requirements will also vary depending upon the size and type of generating unit.

Version 0 standard TOP-002-0 R13 already addresses verification of generating plant real power capability. Therefore, the need for translation of II.B.S1.M2 into this standard without including TOP-002-0 R13 should be assessed. No one needs two standards.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The proposed Standard does not require annual testing – the periodicity for verification is up to the Regional Reliability Organization to specify.

Reliability Standard TOP-002-0 R13 addresses one-time special situation requests, and not periodic validation required for generator model and data as established by Regional procedures.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Version 0 standard TOP-002-0 R13 already addresses verification of generating plant real power capability. Therefore, the need for translation of II.B.S1.M2 into this standard without including TOP-002-0 R13 should be assessed. No one needs two standards.

Required testing for two seasons annually will prove difficult to pass industry consensus. "Annually test to verify…" should be changed to "validate by appropriate means". What is the basis for annual updates versus three years, five years, etc.

In addition to testing, other appropriate validation methods should be defined.

Validation may be achieved through simulation, operating data, field verification readings, engineering evaluations or reviews, and/or testing where appropriate. Validation requirements shall also vary depending upon the size and type of generating unit.

This Standard should be field tested before being adopted.

Reliability Standard TOP-002-0 R13 addresses one-time special situation requests, and not periodic validation required for generator model and data as established by Regional procedures.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Gerald Rheault; Manitoba Hydro

The cost implication for this item is a concern for many entities.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. In addition, the proposed Standard does not require annual testing – the periodicity for verification is up to the Regional Reliability Organization to specify.

These changes should help keep the costs associated with compliance as low as practical while still protecting reliability.

Comments Submitted During Development of Standard on M2

SERC

Recommend the following revisions be made.

M2. Generation equipment owners shall validate by appropriate means ~~test to verify~~ the gross and net real power (MW) ~~dependable~~ capability of their units in accordance with regional requirements as defined by II.B.S1.M1..

The annual testing requirement was removed. What is the basis for annual updates versus three years, five years, etc.?

The Standard was modified as suggested – the testing requirement was replaced to allow any technique acceptable to the associated Regional Reliability Organization, including but not limited to manufacturer data, performance tracking, simulation, analysis and testing.

Dependable was replaced with 'real power (MW) as suggested.

The proposed Standard does not require annual testing – the periodicity for verification is up to the Regional Reliability Organization to specify.

IIB M3 – Verification of gross & reactive power capability

Summary Consideration:

IIBM3 (Verification of Gross and Net Reactive Power Capability of Generators) was modified and translated into a new Standard, MOD-025-1 (Verification of Reactive Power Capability). The new Standard supports the intent of the original Measure, which was to ensure generator gross and net reactive power capability are available and consistent with data used in models and assessments. The requirement to conduct generator testing every five years to verify generator data was replaced with a requirement that Generator Owners 'verify' their data – the revised Requirement does not specify 'how' the Generator Owner must verify its data. Many Stakeholders indicated that generator testing is not the only method for verifying generator data and many Stakeholders indicated that testing every five years isn't necessarily the best timetable. The proposed Standard requires Generator Owners to document their method of verifying generator data in a manner that meets the associated Regional Reliability Organization's (RRO's) requirements. Each RRO may specify how often the verification is needed – the proposed Standard does not include any requirement to conduct verifications every five years.

Many of the Stakeholder concerns highlighted in the comments submitted on this Measure are addressed in the proposed MOD-023-1. In MOD-023-1, each RRO is required to document its procedures for verification of generator modeling and equipment data.

- MOD-023-1_R1.2 states that the RRO's procedures must identify that **a**cceptable methods for model and data verification include but are not limited to manufacturer data, performance tracking, simulation, analysis and testing.
- MOD-023-1_R1.3 requires the RRO to identify the periodicity and schedule of model and data verification.
- MOD-023-1_R1.1 requires the RRO to identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the RRO's model and verification procedures.

Collectively, the proposed Standards address most of the Stakeholder concerns and should be more acceptable than their associated source Measures.

V0 Comments on M3

MAPP Planning Standards Subcommittee

> MAPP is concerned with the extraordinary cost and effort that would be required if Sections 3 through 6 of this standard for generator testing is adopted for compliance. Further, MAPP is concerned that such testing has the possibility of causing generator damage under certain circumstances for certain facilities. MAPP urges the Drafting Team or NERC to pick out a few parameters that are relatively easy and safe to test for and that are clearly needed for system reliability and leave the rest of these sections as a guide. Also, MAPP urges the Drafting Team to provide for a transition period of five or more years for compliance with these standards which have not been field tested

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Tom Brandish – Reliant

> Reactive capability is important to system reliability and Reliant supports system reliability. Reactive testing can present risks to system operation. Looking at unit response when a disturbance occurs on the system may be a better measure of unit reactive capability. It is recommended that units under 50 MW's and that operate less than 100 hours should be excempted from this test.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. Each Regional Reliability Organization's procedures for model and data verification must identify generating unit exemption criteria.

Ed Davis Entergy

R3-1 – should they be required to submit reactive capability curves?

R3-1.a – Should hydrogen pressure be included in the list of functional variables along with real power output, and generator voltage?

Please see the summary consideration. Reliability Standard MOD-023-1 allows the Regional Reliability Organization to specify the data verification parameters to be reported.

SAR Comments on M3

Karl A Bryan; US Army Corps of Engineers - Generators

How are you going to handle environmental limitations, short term operational constraints, seasonal constraints, etc? I think you need to be very concise on what you ask for.

Please see the summary consideration. Reliability Standard MOD-023-1 allows the Regional Reliability Organization to specify the data verification parameters to be reported.

John Horakh; MAAC (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Five year test cycle is arbitrary. Allow operational data to be used instead of a separate test, if adequate

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.

Doug Hils; Cinergy and Lance Hall; Cinergy Generators

Will require tests that are not routinely done today which will impose a cost every five years. Believe this data is important however.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.

Raj Rana; AEP

This data is essential; however the demonstration can be labor intensive and generators have been reluctant to perform these test. NPPs create a special consieration.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Gerald Rheault; Manitoba Hydro

The cost implication for this item is a concerm for many entities.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify. These changes should help keep the costs associated with compliance as low as practical while still protecting reliability.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

It will be difficult to reach industry consensus on generator testing. See comments provided for II.B.S1.M2 for Testing comments.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please see consideration of comments on IIBS1M2.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Version 0 standard TOP-002-0 R13 already addresses verification of generating plant reactive power capability. Therefore, the need for translation of II.B.S1.M2 into this standard without including TOP-002-0 R13 should be assessed. No one needs two standards.

The amount of testing described in the current version of this measurement will place a strain on generating plant resources and frequently place the grid into an abnormal state during the subject tests. For example, it will create concerns if capacitors must be switched off to test the reactive capability of a large generator in an isolated area during summer-type load demand periods. This is especially true if the testing is on a generator at or near a nuclear plant.

Many of the Regions have recognized the problems with performing these tests and have established task forces to address the generator owner/operator concerns along with the transmission system planners and operators need to know plant reactive capabilities. It is recommended that the new standard direct each region to establish its own requirements and not establish one set of rules for all regions.

Reliability Standard TOP-002-0 R13 addresses one-time special situation requests, and not periodic validation required for generator model and data as established by Regional procedures.
Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.
Each Regional Reliability Organization is required to establish its own requirements for model and data verification under MOD-023-1.

Brandon Snyder; Duke Energy

The GS has expressed concerns that the requirement to test a units reactive capability could lead to the grid being placed frequently into a condition where the ability to mitigate nuclear accidents could be compromised. In the SERC IIB supplement, the first step to verifying the reactive capability is to see if operating data is sufficient to validate numbers. If not, an evaluation is required prior to the commencement of MVAR validation testing at any generator, to assure testing at nearby plants will not adversly affect the ability of the grid to support emergency nuclear plant loads.

For testing at a nuclear plant, concerns have not been addressed about how a test can be conducted due to NRC 10CFR50.59 regulations, which require the plant operator to assure testing will not impact plant safety. Also, an approach of basing MVAR support only on values demonstrated by test results would likely lead to underestimateing the amount of VAR support available from large plants, which will swing voltage.

This requirement discusses using analysis to justify VAR capability beyond any capability validated through testing. There needs to be a guidence document developed showing acceptible methods for doing this analyses

Tom Pruitt has expressed concerns with VAR testing from a Grid OPS perspective. These concerns touch on the need to have a team effort to assure VAR testing will not cause violation of other NERC requirments on maintaining voltage schedule.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Christopher Schaeffer; Duke Energy

The SERC GS has concerns that the requirement to test a units reactive capability could lead to the grid being placed frequently into a condition where the ability to mitigate nuclear accidents could be compromised. In the SERC IIB supplement, the first step to verifying the reactive capability is to see if operating data is sufficient to validate numbers. If not, an evaluation is required prior to the commencement of MVAR validation testing at any generator, to assure testing at nearby plants will not adversly affect the ability of the grid to support emergency nuclear plant loads.

For testing at a nuclear plant, concerns have not been addressed about how a test can be conducted due to NRC 10CFR50.59 regulations, which require the plant operator to assure testing will not impact plant safety. Also, an approach of basing MVAR support only on values demonstrated by test results would likely lead to underestimateing the amount of VAR support available from large plants, which will swing voltage.

This requirement discusses using analysis to justify VAR capability beyond any capability validated through testing. There needs to be a guidence document developed showing acceptible methods for doing this analyses VAR testing activities need to be planned such that testing will not cause violation of other NERC requirments on maintaining voltage schedule.

This requirement discusses using analysis to justify VAR capability beyond any capability validated through testing. There needs to be a guidence document developed showing acceptible methods for doing this analyses VAR testing activities need to be planned such that testing will not cause violation of other NERC requirments on maintaining voltage schedule.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Peter Burke; ATC

System operation may limit the ability for testing . Need to define real power level unit output coincident with verification process.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Tom Mielnik; MidAmerican Energy

The qualification that "if safety or system conditions do not allow testing to full capability, computations and engineering reports of estimated capability shall be provided" must be retained to get this standard approved. It would help if realistic testing is detailed for gorss and net reactive power capability. This standard should be field tested first.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

What is the basis for the 5-year update?
Regarding "testing", see comments provided for II.B.S1.M2.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

The issues arise when the units can not reach the reactive power levels due to system conditions. The creation of an easy and accurate calculation method needs to be developed. This calculation can not predict issues of vibration , overheating and relay issues.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Comments Submitted During Development of Standard on M3

SERC

Recommend the following revisions be made.

M3. Generation equipment owners shall validate by appropriate means the gross and net reactive power (Mvar) capability of their units in accordance with regional requirements as defined by II.B.S1.M1.

The five-year testing requirement was removed. What is the basis for a five-year update versus three years, six years, etc.? Recommend an update cycle of six years.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. The periodicity of the verification is left to the Regional Reliability Organization to specify.

IIB M4 – Test results of generator voltage regulator controls & limit functions

Summary Consideration:

- IIB M4 (Test Results of Generator Voltage Regulator Controls and Limit Functions) was merged with IIBM6 (Verification of excitation system dynamic modeling data) to form a new Standard MOD-026-1 (Verification and Modeling of Generator Excitation Systems and Voltage Controls).

The new Standard supports the intent of the original Measures, which was to verify that generator excitation system functions are available and consistent with models used to assess Bulk Electric System reliability.

The original requirements to conduct generator testing were replaced with requirements for Generator Owners to 'verify' their data – the revised Requirements do not specify 'how' the Generator Owner must verify its data. Many Stakeholders indicated that generator testing is not the only method for verifying generator data and many Stakeholders indicated that re-validating data every five years may not be appropriate. The proposed Standard requires Generator Owners to document their method of verifying generator data in a manner that meets the associated Regional Reliability Organization's (RRO's) requirements. The new proposed Standard does not include any requirement that identifies the specificity for generator modeling and equipment data verifications.

Many of the Stakeholder concerns highlighted in the comments submitted on this Measure are addressed in the proposed MOD-023-1. In MOD-023-1, each RRO is required to document its procedures for verification of generator modeling and equipment data.

- MOD-023-1_R1.2 states that the RRO's procedures must identify that **a**cceptable methods for model and data verification include but are not limited to manufacturer data, performance tracking, simulation, analysis and testing.
- MOD-023-1_R1.3 requires the RRO to identify the periodicity and schedule of model and data verification.
- MOD-023-1_R1.1 requires the RRO to identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the RRO's model and verification procedures.

Collectively, the proposed Standards address most of the Stakeholder concerns and should be more acceptable than their associated source Measures.

V0 Comments on M4

MAPP Planning Standards Subcommittee

MAPP is concerned with the extraordinary cost and effort that would be required if Sections 3 through 6 of this standard for generator testing is adopted for compliance. Further, MAPP is concerned that such testing has the possibility of causing generator damage under certain circumstances for certain facilities. MAPP urges the Drafting Team or NERC to pick out a few parameters that are relatively easy and safe to test for and that are clearly needed for system reliability and leave the rest of these sections as a guide. Also, MAPP urges the Drafting Team to provide for a transition period of five or more years for compliance with these standards which have not been field tested

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Tom Brandish – Reliant

Generator voltage regulator testing on units with older analog systems do not have provisions to determine the mentioned data points without extensive additional test equipment. If this test is required by the region then a mechanism needs to be in place to reimburse the generator for conducting this test. It is recommended that units under 50 MW's and that operate less than 100 hours should be excempted from this test.

Please see the summary consideration. Each Regional Reliability Organization must identify generating unit exemption criteria.

SAR Comments on M4

Christopher Schaeffer; Duke Energy (Brandon Snyder; Duke Energy)

SERC IIB Guide allows for off-line testing and a Open Circuit Step Response test for regulator control and limit validation. We have no concerns as long as the SERC IIB supplement guidelines are used.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Karl A Bryan; US Army Corps of Engineers - Generators

Again, recommend performance based requirements and a certification process for those gathering the data. Also recommend that the Transmission Service Provider be responsible for verifying the data when used in studies does converge, this would be a confidence check on the data.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Addressing the certification of personnel is outside the scope of this set of Standards.

Doug Hils; Cinergy

Will require tests that are not routinely done today which will impose a cost every five years. Believe this data is important however.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Lance Hall; Cinergy (Generators)

Will require tests that are not routinely done today which will impose a cost every five years

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Peter Burke; ATC

May be costly and time consuming if testing is being considered.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Gerald Rheault; Manitoba Hydro

The cost implication for this item is a concerm for many entities.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Version 0 standards MOD-010-0, MOD-011-0, and MOD-012-0 already contain requirements for Generator Owners to provide appropriate equipment data for modeling purposes in accordance with Regional requirements.

Therefore, the need for translation of II.B.S1.M4 into this standard without including the operating standards should be assessed. No one needs multiple standards.

This Standard should be field tested before being adopted.

The data to be provided for modeling under the MOD-010 through MOD-013 Standards is not as specific as the data required in this standard. This standard also includes requirements for verifying the data.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Tom Mielnik; MidAmerican Energy

> Realistic testing requirements for voltage regulatory controls needs to be fleshed out before this standard is adopted. Perhaps a qualification that "if safety or system conditions warrant, computations and engineering reports shall be provided in lieu of testing" will help get this standard approved. This standard should be field tested first.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

> What is the basis for the 5-year update?
> Regarding "testing", see comments provided for II.B.S1.M2. "Voltage regulator controls" and "excitation systems" should be combined to state "voltage regulator and excitation control systems".

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please see consideration of comments on IIBS1M2.

John Horakh; MAAC (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

> Five year test cycle is arbitrary. A physical survey to verify the equipment installed and in service, and to note settings, may be adequate

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

> Issues related to testing procedures will arise and be difficult to resolve due to the wide varity of regulators in use. The intent of the standard will need to be defined to help with this issue.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Raj Rana; AEP

> Generator reluctance to undertake the tests

Comments Submitted During Development of Standard on M4:
SERC

> Recommend the following revisions to combine voltage regulator and excitation control systems.
> M4. Generation equipment owners shall validate by appropriate means the voltage regulator and excitation control systems, including limit functions ~~at least every five years~~ in accordance with regional requirements as defined by II.B.S1.M1.
> The five-year testing requirement was removed. What is the basis for a five-year update versus three years, six years, etc.? Recommend an update cycle of six years.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify. In the proposed Standard, the Generator Owner is required to provide the RRO and TP with the results of excitation system (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) functions.

IIB M5 – Test results of speed/load governor controls

Summary Consideration:

IIBM5 (Test Results of Speed/Load Governor Controls) was merged with IIBM9 (Speed/Load Governing System) and converted into a new Standard, MOD-027-1 (Verification and Status of Generator Frequency Response). The new Standard supports the intent of both of the original Measures, which was to provide verification and status of generator frequency response for use in models for reliability studies.

The original requirements to conduct generator testing were replaced with requirements for Generator Owners to 'verify' their data – the revised Requirements do not specify 'how' the Generator Owner must verify its data. Many Stakeholders indicated that generator testing is not the only method for verifying generator data and many Stakeholders indicated that re-validating data every five years may not be appropriate. Other Stakeholders indicated concerns that testing may not be feasible. The Drafting Team recognizes that there are technical issues with the speed governor models that need to be resolved. The proposed Standard simply requires the Generator Owners to evaluate how their unit's MW output is expected to respond to frequency and report that information to the Transmissions Planner and Regional Reliability Organization (RRO). The proposed Standard requires Generator Owners to document their method of verifying generator data in a manner that meets the associated RRO's requirements. The new proposed Standard does not include any requirement that identifies the specificity for generator modeling and equipment data verifications.

Many of the Stakeholder concerns highlighted in the comments submitted on this Measure are addressed in the proposed MOD-023-1. In MOD-023-1, each RRO is required to document its procedures for verification of generator modeling and equipment data.

- MOD-023-1_R1.2 states that the RRO's procedures must identify that acceptable methods for model and data verification include but are not limited to manufacturer data, performance tracking, simulation, analysis and testing.
- MOD-023-1_R1.3 requires the RRO to identify the periodicity and schedule of model and data verification.
- MOD-023-1_R1.1 requires the RRO to identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the RRO's model and verification procedures.

Collectively, the proposed Standards address most of the Stakeholder concerns and should be more acceptable than their associated source Measures.

V0 Comments on M5

FRCC

Specific test requirements should be included in this standard. In addition, to a procedure or guidelines for data collection to ensure uniformity.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. Each Regional Reliability Organization is required to specify what data it needs.

Ed Davis Entergy

R5-1 – should they be required to submit graphs of the governor droop characteristics?

Please see the summary consideration. Each Regional Reliability Organization is required to specify what data it needs.

MAPP Planning Standards Subcommittee

MAPP is concerned with the extraordinary cost and effort that would be required if Sections 3 through 6 of this standard for generator testing is adopted for compliance. Further, MAPP is concerned that such testing has the possibility of causing generator damage under certain circumstances for certain facilities. MAPP urges the Drafting Team or NERC to pick out a few parameters that are relatively easy and safe to test for and that are clearly needed for system reliability and leave the rest of these sections as a guide. Also, MAPP urges the Drafting Team to provide for a transition period of five or more years for compliance with these standards which have not been field tested

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years.

Tom Brandish – Reliant

Generator governor droop on units with older analog systems was preset at the factory. Additional test equipment is required to conduct this test. If this test is required by the region, then a mechanism needs to be in place to reimburse the generator for conducting this test. It is recommended that units under 50 MW's and that operate less than 100 hours should be excempted from this test.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. Each Regional Reliability Organization must identify generator exemption criteria in its procedures for model and data verification. Addressing reimbursements is outside the scope of this set of Standards.

SAR Comments on M5

Gerald Rheault; Manitoba Hydro

The cost implication for this item is a concerm for many entities.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years. These changes should help reduce the costs associated with compliance.

Peter Burke; ATC

May be costly and time consuming if testing is being considered.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years. These changes should help reduce the costs associated with compliance.

Karl A Bryan; US Army Corps of Engineers - Generators

Again, recommend performance based requirements and a certification process for those gathering the data. Also recommend that the Transmission Service Provider be responsible for verifying the data when used in studies does converge, this would be a confidence check on the data.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Addressing the certification of personnel is outside the scope of this set of Standards.

Christopher Schaeffer; Duke Energy (Brandon Snyder; Duke Energy)

It's not clear what testing could be done at a generation plant to accurately determine speed governor settings at typical unit operating MW. The SERC IIB supplement recognizes this and uses a new approach to model validation using generator operating data during frequency transients. This standard, along with the IIICM9 requirement should instead, require the Generator Owner/Operator and the Transmission Provider to work together as necessary to assure the frequency response characteristics of significant generating units are understood and modeled appropriately.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The Drafting Team recognizes that there are technical issues with the speed governor models that need to be resolved. The proposed Standard requires the Generator Owner to evaluate how its unit's MW output is expected to respond to frequency and report that information to the Transmissions Planner and RRO.

Doug Hils; Cinergy and Lance Hall; Cinergy (Generators)

Will require tests that are not routinely done today which will impose a cost every five years. Believe this data is important however.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years. These changes should help reduce the costs associated with compliance.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

Present methods are relatively easy to perform with some calling for the governor to be sent to a shop for testing. The validity of each method will need to be discussed. The ASME method of testing is extremely complicated and will be difficult to follow if required.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

It will be difficult to reach industry consensus on generator testing. See comments provided for II.B.S1.M2 for Testing comments.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please see consideration of comments on IIBS1M2.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

How to comply with this requirement has been the focus of much debate within the Power Generation community. At present it is unclear what type of testing could and should be done to accurately determine speed governor settings and response characteristics. It is also recognized that the governor response along does not represent the how the unit may respond to system frequency excersion.

Some Regional IIB supplements recognize this fact and have proposed a new approach to model validation using generator operating data during system transients. Work on this standard should be posponded until better technical direction has been developed.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The Drafting Team recognizes that there are technical issues with the speed governor models that need to be resolved. The proposed Standard requires the Generator Owner to evaluate how its unit's MW output is expected to respond to frequency and report that information to the Transmissions Planner and Regional Reliability Organization.

Tom Mielnik; MidAmerican Energy

Realistic testing requirements for speed/load governor controls needs to be fleshed out before this standard is adopted. Perhaps a qualification that "if safety or system conditions warrant, computations and engineering reports shall be provided in lieu of testing" will help get this standard approved. This standard should be field tested first.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The Drafting Team recognizes that there are technical issues with the speed governor models that need to be resolved. The proposed Standard requires the Generator Owner to evaluate how its unit's MW output is expected to respond to frequency and report that information to the Transmissions Planner and Regional Reliability Organization.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

See comments provided for II.B.S1.M2 and M3.

See consideration of comments provided for IIBS1M2 and M3.

John Horakh; MAAC (Michael Calimano; NYISO) (ISO/RTO Council (9)) (Peter Henderson; IESO)

Five year test cycle is arbitrary. A physical survey to verify the equipment installed and in service, and to note settings, may be adequate

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years.

Comments Submitted During Development of Standard on M5

SERC

Recommend the following revisions be made.

M5. Generation equipment owners shall validate by appropriate means speed/load governor controls in accordance with regional requirements as defined by II.B.S1.M1..

The five-year testing requirement was removed. What is the basis for a five-year update versus three years, six years, etc.? Recommend an update cycle of six years. However, we also recommend that any governor testing requirements be delayed until industry modeling issues are addressed (i.e. IEEE Power Systems Stability Subcommittee work).

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years.

The Drafting Team recognizes that there are technical issues with the speed governor models that need to be resolved. The proposed Standard requires the Generator Owner to evaluate how its unit's MW output is expected to respond to frequency and report that information to the Transmissions Planner and Regional Reliability Organization.

IIB M6 – Verification of excitation system dynamic modeling data

Summary Consideration:

IIB M6 (Verification of Excitation System Dynamic Modeling Data) was merged with IIBM4 (Test Results of Generator Voltage Regulator Controls and Limit Functions) to form a new Standard, MOD-026-1 (Verification and Modeling of Generator Excitation Systems and Voltage Controls).

The new Standard supports the intent of both of the original Measures, which was to verify that generator excitation system functions are available and consistent with models used to assess Bulk Electric System reliability.

The original requirements to conduct generator testing were replaced with requirements for Generator Owners to 'verify' their data – the revised Requirements do not specify 'how' the Generator Owner must verify its data. Many Stakeholders indicated that generator testing is not the only method for verifying generator data and many Stakeholders indicated that re-validating data every five years may not be appropriate. The proposed Standard requires Generator Owners to document their method of verifying generator data in a manner that meets the associated Regional Reliability Organization's (RRO's) requirements. The new proposed Standard does not include any requirement that identifies the specificity for generator modeling and equipment data verifications.

Many of the Stakeholder concerns highlighted in the comments submitted on this Measure are addressed in the proposed MOD-023-1. In MOD-023-1, each RRO is required to document its procedures for verification of generator modeling and equipment data.

- MOD-023-1_R1.2 states that the RRO's procedures must identify that **a**cceptable methods for model and data verification include but are not limited to manufacturer data, performance tracking, simulation, analysis and testing.
- MOD-023-1_R1.3 requires the RRO to identify the periodicity and schedule of model and data verification.
- MOD-023-1_R1.1 requires the RRO to identify generating unit exemption criteria including documentation of those units that are exempt from a portion or all of the RRO's model and verification procedures.

Collectively, the proposed Standards address most of the Stakeholder concerns and should be more acceptable than their associated source Measures.

V0 Comments on M6

MAPP Planning Standards Subcommittee

> MAPP is concerned with the extraordinary cost and effort that would be required if Sections 3 through 6 of this standard for generator testing is adopted for compliance. Further, MAPP is concerned that such testing has the possibility of causing generator damage under certain circumstances for certain facilities. MAPP urges the Drafting Team or NERC to pick out a few parameters that are relatively easy and safe to test for and that are clearly needed for system reliability and leave the rest of these sections as a guide. Also, MAPP urges the Drafting Team to provide for a transition period of five or more years for compliance with these standards which have not been field tested

Please see the summary consideration. Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

FRCC

> Specific test requirements should be included in this standard. In addition, to a procedure or guidelines for data collection to ensure uniformity.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.
Each Regional Reliability Organization is free to be as specific as needed in developing its procedures for verification of model and data verification.

Tom Brandish – Reliant

> Generator excitation system tests that require tripping a unit even at low output values is a concern for potential equipment damage. It is recommended that units under 50 MW's and that operate less than 100 hours should be exempted from this test. Also, it is unrealistic to require data on a new excitation system 1 year in advance. This information is not established that early in the process.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify. Each Regional Reliability Organization may specify criteria for generator exemption from its procedures for model and data verification.

SAR Comments on M6

Gerald Rheault; Manitoba Hydro

> The cost implication for this item is a concerm for many entities.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify. These changes should help with concerns over costs of compliance.

Karl A Bryan; US Army Corps of Engineers - Generators

> Again, recommend performance based requirements and a certification process for those gathering the data. Also recommend that the Transmission Service Provider be responsible for verifying the data when used in studies does converge, this would be a confidence check on the data.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data. Addressing the certification of personnel is outside the scope of this set of Standards. The details of what should be included in verification are left to the Regional Reliability Organizations to specify.

Doug Hils; Cinergy and Lance Hall; Cinergy (Generators)

> Will require tests that are not routinely done today which will impose a cost every five years. Believe this data is important however.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Ed Davis; Entergy Services

> Development of this standard will be viewed upon by many as a new requirement, and will likely face stiff opposition.

The Phase III/IV Planning Standards have undergone some portion of a standards review process and should not be considered, ‘new requirements’.

Brandon Snyder; Duke Energy

> We do not have concerns, as long as the SERC II B supplement guidence is used, which uses an open circuit step response test to validate response.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Raj Rana; AEP

Generator reluctance to undertake the tests

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Transmission Issues Subcommittee(?)

Obtaining industry consensus on implementation will be difficult.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and most of the comments submitted during the initial development of this Measure centered on ‘testing’.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

It will be difficult to reach industry consensus on generator testing. See comments provided for II.B.S1.M2 for Testing comments.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.
Please see consideration of comments on IIBS1M2.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Version 0 standards MOD-010-0, MOD-011-0, and MOD-012-0 already contain requirements for Generator Owners to provide appropriate equipment data for modeling purposes in accordance with Regional requirements. Therefore, the need for translation of II.B.S1.M6 into this standard without including the operating standards should be assessed. No one needs multiple standards. The magnitude of work required to comply with this standards is also a factor. It will take many years to perform all the work required to comply with it. Thus, it is very important that the methods for accomplishing this requirement be technically sound and will provide the desired results.

The data to be provided for modeling under the MOD-010 through MOD-013 Standards is not as specific as the data required in this standard. This standard also includes requirements for verifying the data.

Peter Burke; ATC

May be costly and time consuming if testing is being considered.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Tom Mielnik; MidAmerican Energy

Realistic testing requirements for excitation system dynamic modeling data needs to be fleshed out before this standard is adopted. Perhaps a qualification that "if safety or system conditions warrant, computations and engineering reports shall be provided in lieu of testing" will help get this standard approved. This standard should be field tested first.

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

What is the basis for the 5-year update?

Regarding "testing", see comments provided for II.B.S1.M2.

Please see the summary consideration. The proposed Standard does not include a requirement that the verification be conducted at least once every 5 years.
See consideration of comments on IIBS1M2.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Five year test cycle is arbitrary. A physical survey to verify the equipment installed and in service, and to note settings, may be adequate. Open circuit test may not be the best or only test needed

Please see the summary consideration. Testing is no longer the only acceptable method of verifying models and data and the periodicity of the verification is left to the Regional Reliability Organization to specify.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

Standardized testing has not been developed and will be difficult to accomplish. The intended purpose of this standard needs to be clearly defined to help develop a proper testing method.

Please see the summary consideration. The purpose of the new Standard clearly focuses on the intent, which is to verify that generator excitation system functions are available and consistent with models used to assess Bulk Electric System reliability. Testing is no longer the only acceptable method of verifying models and data.

Comments Submitted During Development of Standard on M6

SERC

Recommend that II.B.S1.M6 be deleted since all requirements for this measurement are covered in the above recommended revision to II.B.S1.M4. Schedule and open circuit response should be address on a regional basis per procedures required by II.B.S1.M1.

Please see the summary consideration. M4 and M6 were revised and merged into a single Standard and require conformance to Regional Procedures identified under MOD-023-1 (old IIBS1M1).

IID – Actual & Forecast Demands

Comments Relevant to Multiple Measures
Summary Consideration:

There are two Measures in this series – IIDM2 and IDM3.
- IIDM2 (Procedures regarding use of customer demand data) was modified and translated into Reliability Standard MOD-016-1 (Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management).
- IIDM3 (Procedures Requiring Consistency of Data) was not translated because Stakeholders indicated the Measure is not needed for reliability.

IIDM3 (Procedures Requiring Consistency of Data), requires consistency between the demand data reported to government entities and the demand data reported to reliability entities. Several commenters recommended that this measure be deleted because there is no way to objectively measure compliance, and because reporting data to government entities is not necessarily a reliability issue.

V0 Comments on Multiple Measures:
Paul Arnold – BPA

Purpose indicates "To ensure that assessments and validation of past events AND DATABASES…". The words shown in capitals seem to confuse the description and should be removed. These words do not appear to be included in the existing criteria.

Data in databases does need to be validated.

Bob Millard – MAIN

This standard is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard. Based on the assumption that the subject material is essentially already covered by EIA, FERC, etc. requirements, this entire standard should not move forward in Version 0.

Some of this original set of IID Measures (IIDM1, IIDM4, IIDM5, IIDM6, IIDM7and IIDM8) were approved as part of Version 0 – the Phase III & IV Drafting Team is recommending that IIDM3 be eliminated based on Stakeholder comments that it is not needed for reliability.

Frank McElvain - Tri-State G&T

It is not clear what benefit would be gained from describing the procedure by which a reporting entity eliminates double counting and avoids omitting loads in reports. In contrast, there is no similar requirement described for ensuring that generating capability is reported on a consistent basis, or that transmission line length is measured accurately. It would be sufficient to simply state, in written documentation accompanying load data submittals, that care has been taken to avoid such errors, without describing in detail each step taken to ensure information is accurate and reliable.

Agree that a procedure is not needed, however a requirement to not double count or miss loads is needed to preserve reliability.

Comments Submitted During Development of Standard on Multiple Measures
SERC
II.D.S1.M2 and II.D.S1-S2.M3

Recommend that these measurements be deleted, or made guides. In addition, the SERC PSWG position on the II.D measurements remains the same as commented on for the Phase II/A measurements (see below).

Agree that a procedure is not needed, however a requirement to not double count or miss loads is needed to preserve reliability.

> "II.D Templates: The filing requirements of the twelve (12) II.D templates are very repetitive and time consuming. All of this data is contained in two reports that are filed annually (FERC-714 and EIA-411). The EIA-411 is presently filed with the regions on an annual basis and in the same approximate time frame as the NERC Planning Standards II.D filing requirements. Some non-jurisdictional utilities may not make a FERC-714 filing. The non-jurisdictional utilities should be required to start filing the FERC-714 report, since the II.D measurements require this data to be filed with the regions. Based on the above, it is recommended that the II.D requirements be changed to require that only these two reports be required to satisfy all II.D filing requirements. This will simplify the reporting and compliance monitoring requirements for the II.D measurements."

Agree and this requirement has been eliminated.

IID M2 – Procedures regarding use of customer demand data

Summary Consideration:

IID M2 (Procedures Regarding Use of Customer Demand Data) was merged into the already approved Standard, MOD-016 (Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management).

- The proposed Standard does not require a 'procedure' to identify how the Regional Reliability Organization will ensure there is no double counting of customer data – instead the proposed Standard requires the Regional Reliability Organization to include in the documentation of its data reporting requirements, a requirement that actual, forecast, and controllable DSM demand data not be include duplications or omissions.
- The levels of non-compliance no longer address, 'completeness' since this is difficult to objectively measure.

The proposed modifications address most of the Stakeholder concerns and should be more acceptable than its associated source Measure.

V0 Comments on M2

Consumers

Replace with Planning Authority and Regional Reliability Council (Sections 1 & 2) Load Serving Entity, Planning Authority and Resource Planner (Sections 3-8)

Agree. This change has been made.

Raj Rana – AEP

As in R1-1, Version 0 reference the Generation owner, but lists transmission facilities. If a generation owner (such as an IPP) also owns transmission facilities, such as terminal equipment, then that generation owner is also a transmission owner.

The V0 translation of IIDM2 identified the Regional Reliability Organization and the Planning Authority as the responsible entities.

FRCC

This measure states that the Load Serving Entity, Planning Authority and Resource Planner "shall provide evidence ", but there is no indication of which entities will receive the evidence.

The proposed Standard, (MOD-016-1) now states that the Transmission Planner and Regional Reliability Organization shall each provide evidence to its Compliance Monitor

SAR Comments on M2

Lance Hall; Cinergy Generators (Doug Hils; Cinergy)

Recommend combining this with II.D.S1.M1 or eliminating it. Should be obvious that any reporting procedure should ensure against double counting so why make a standard?

Agree. This change has been made.

Ed Davis; Entergy Services

Should be eliminated, or added to II.D.M1.

Agree. This change has been made.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first. Five business days is not reasonable.

The Drafting Team is recommending that this Standard not be Field Tested because many entities are already complying with this measure.

Most commenters seemed to agree with the five business days, so this was not changed.

Peter Burke; ATC

> In some cases, there may be three or four levels at which customer demand could be reported (e.g. TP/TO, LSE, DP). Deciding who should and who is willing to collect the data is not a trivial task.

Agree.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

> This Standard should be field tested before being adopted.

The Drafting Team is recommending that this Standard not be Field Tested because many entities are already complying with this measure.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

Raj Rana; AEP

> This is a subset of Measure 1 and is not required in a Version 0 Standard.

This has been added to MOD-016.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

> Recommend deleting or listing as a bullet item under an existing II.D. measure. If left in, this needs to be moved to the Modeling SAR.

Agree. The proposed revision to MOD-016 reflects this change.

Karl A Bryan; US Army Corps of Engineers - Generators

> Instituting a process that verifies the data that also has a QA/QC aspect.

This recommendation goes beyond the scope of the intent of the original set of Standards.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

> Very difficult to measure whether the procedures are "complete" or "incomplete," for compliance or non-compliance

The measure was moved to MOD-016, and the associated levels of Non-compliance do not assess, ‘completeness’.

Ray Morella; FirstEnergy

> How does the standard involving the double counting or omission of customer load data relate to this standard? This sounds more like something associated with UVLS or UFLS standards or operating guides. Should be put in Modeling SAR.

The load that is addressed in this Standard is not just load subject to UVLS or UFLS, it is ‘all load’. This was moved to the Modeling SAR (MOD-016-1) as suggested.

IID M3 – Procedures requiring consistency of data

Summary Consideration:

The original Measure, IIDM3 (Procedures Requiring Consistency of Data), requires consistency between the demand data reported to government entities and the demand data reported to reliability entities. Several commenters recommended that this measure be deleted because there is no way to objectively measure compliance, and because reporting data to government entities is not necessarily a reliability issue.

To ensure reliability, the loads reported for reliability purposes must be accurate, but this requirement is established in TPL-001, TPL-002, TPL-003 and TPL-004. While it may be prudent to ensure that data submitted to government agencies is consistent with data used for reliability assessments, there is no impact to reliability if the loads reported to government agencies are different than the loads used for reliability assessments since government agencies are not responsible for performing reliability assessments.

Load forecast information is continually changing and forcing load forecast information to be consistent with that used in reliability assessments will only result in less up to date data being provided to government agencies. If government agencies desire load data to be consistent with NERC reporting requirements, they should so stipulate in their data requests.

The Drafting Team did not translate IIDM3 into a Reliability Standard and did not attempt to provide responses to individual comments. The Drafting Team will ask Stakeholders if they agree that this Measure should not move forward for approval.

V0 Comments on M3

Consumers

Replace with Planning Authority and Regional Reliability Council (Sections 1 & 2) Load Serving Entity, Planning Authority and Resource Planner (Sections 3-8)

Raj Rana AEP

Requirement not measurable, delete section.

Frank McElvain - Tri-State G&T

Recently, WECC members were asked to provide load information aggregated on a “Control Area” basis. The term, “Control Area”, does not appear in Section 3’s list of aggregation levels. To be sure, the term “subregional” may be interpreted to include Control Areas, but it would be clearer if the term “subregional” were replaced with “subregional or control-area”.

SAR Comments on M3

Lance Hall; Cinergy Generators (Doug Hils; Cinergy

Recommend combining this with II.D.S1.M1 or eliminating it.

Ed Davis; Entergy Services

II.D.M1 states that data must be consistent for I.B, II.A, and II.D. That covers the requirement of II.D.M3, and thus this measurement should be eliminated.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first.

Karl A Bryan; US Army Corps of Engineers - Generators

Sounds like you are trying to herd cats. Getting people to consistently fill out even the simplest form is a monumental task.

Ray Morella; FirstEnergy

Implementation of comment format.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

This Standard should be field tested before being adopted.

Raj Rana; AEP

Measure requires consistency of demand data reported to government entities and to reliability entities, how can this be measurable?

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

Recommend deleting or listing as a bullet item under an existing II.D. measure. If left in, this needs to be moved to the Modeling SAR.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Peter Henderson; IESO) (Michael Calimano; NYISO)

Unclear if this requires procedures for consistency, as in Full Compliance, or consistent data, as in Levels of Non-Compliance

IIE – Demand Characteristics

Summary Consideration:

There are three Measures in this series – IIEM1, IIEM2 and IIEM3. These Measures all address dynamic customer demand data.

IIEM1 – Voltage & Frequency Characteristics of Customer Demands
IIEM2 – Determining Dynamic Characteristics of Customer Demands
IIEM3 – Customer (Dynamic) Demand Data

While the objectives of the III.E.M1 through M3 Measures are important to grid reliability, the Drafting Team recommends deleting these Measures because Stakeholders indicated there is currently no accepted method of developing dynamic load characteristics of power system loads. The Drafting Team did not attempt to provide individual responses to the comments submitted on these Measures. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing Standards now would not be effective since there would be no way to establish if the models provided were accurate, making the associated Measures unenforceable. The Drafting Team recommends that a SAR be submitted for Standards development once there are accurate methods for developing and validating dynamic load models.

V0 Comments on Multiple Measures:

Bob Millard – MAIN

This entire standard should not move forward in Version 0 since it is essentially already covered by STD 058. In addition it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard. Not well defined and/or detailed, needs further drafting for implementation

SPP

Should be deleted from Version 0 because it shifts the burden from merely developing a representative model to developing detailed representations. In very specialized studies such information may be needed, but not on any regular basis.

Bill Bojorquez – ERCOT

The Planning Authority or RRCs should gather, review and utilize dynamic characteristics of customer demand for its reliability assessment - not develop the information. Transmission Planners or Load Serving entities are better suited to provide this information. These entities may chose to report "upward" to the Planning Authority. However, the other organizations would retain accountability for the information reported to the Planning Authority.

IIE M1 – Voltage & frequency Characteristics of customer demands

Summary Consideration:
There are three Measures in this series – IIEM1, IIEM2 and IIEM3. These Measures all address dynamic customer demand data.

IIEM1 – Voltage & Frequency Characteristics of Customer Demands
IIEM2 – Determining Dynamic Characteristics of Customer Demands
IIEM3 – Customer (Dynamic) Demand Data

While the objectives of the III.E.M1 through M3 Measures are important to grid reliability, the Drafting Team recommends deleting these Measures because Stakeholders indicated there is currently no accepted method of developing dynamic load characteristics of power system loads. The Drafting Team did not attempt to provide individual responses to the comments submitted on this Measure. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing Standards now would not be effective since there would be no way to establish if the models provided were accurate, making the associated Measures unenforceable. The Drafting Team recommends that a SAR be submitted for Standards development once there are accurate methods for developing and validating dynamic load models.

V0 Comments on M1:
Raj Rana AEP
Should be applicable to the Planning Authorities and the transmission planner.

William Smith – Allegheny
Transmission Planner should be added to Planning Authorities

SAR Comments on M1:
Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)
This Standard is better suited to be handled separately from the Phase III/IV blackout recommendation Standards. More appropriate for a research project.
This Standard should be field tested before being adopted.

Karl A Bryan; US Army Corps of Engineers - Generators
Make sure you have concise enough instructions of what you are after so that the information you gather from those required to submit data results in useable data.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)
Unclear how the Regional determination of dynamic demand characteristics (II.E.S1.M1) fits in with the Interconnections' determination of dynamic demand characteristics (II.E.S1.M2)

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE) (SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC))
There is no agreed upon or approved method to accomplish this. This is more appropriate for a research project than a standard.

Brandon Snyder; Duke Energy
As long as these are just providing plans – then this may be ok to approve. Duke does not currently have any plans, but does have some ideas about how to do this with new/existing equipment

Peter Burke; ATC
Information not be readily available and difficult to obtain. May be able to make generalizations of load characteristics.

Tom Mielnik; MidAmerican Energy

Needs to have the qualification that this is not required for systems not susceptible to instability. This standard should be field tested first.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

How will this be accomplished? Extremely costly and time consuming. Is it worth it for all or just a defined few that studies indicated a need? Need special equipment to measure characteristics.

Comments Submitted During Development of Standard on M1

SERC

Recommend that this measurement be made a guide. In addition, we encourage the use of EPRI, IEEE, etc. research being done in this area for enhancement of dynamic models.
If the measurement is retained, it should be revised by adding the following: "Determinations may be made by tests or by research and analysis of the load types."

Testing for all the loads would require a significant investment in capital and it would take many years to develop data for a substantial part of the system. It is also anticipated that large disturbances would be required to obtain frequency data and these events are not common. It is believed that information can be obtained from utility records that indicate the type of load and industry resources on load representation (EPRI, IEEE etc.) can be used to classify and approximate the load composition with sufficient accuracy in a greatly reduced time.

IIE M2 – Determining dynamic characteristics of customer demands

Summary Consideration:
There are three Measures in this series – IIEM1, IIEM2 and IIEM3. These Measures all address dynamic customer demand data.

IIEM1 – Voltage & Frequency Characteristics of Customer Demands
IIEM2 – Determining Dynamic Characteristics of Customer Demands
IIEM3 – Customer (Dynamic) Demand Data

While the objectives of the III.E.M1 through M3 Measures are important to grid reliability, the Drafting Team recommends deleting these Measures because Stakeholders indicated there is currently no accepted method of developing dynamic load characteristics of power system loads. The Drafting Team did not attempt to provide individual responses to the comments submitted on this Measure. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing Standards now would not be effective since there would be no way to establish if the models provided were accurate, making the associated Measures unenforceable. The Drafting Team recommends that a SAR be submitted for Standards development once there are accurate methods for developing and validating dynamic load models.

V0 Comments on M2

Ameren

Refers to NERC SDDWG. Does this group exist or merged within MMWG?

Guy Zito - NPCC and Brandian - ISO-NE

If the Std remains in the Version 0; Delete specific about "Hydro-Quebec Interconnection".

Pete Henderson – IMO and Guy Zito – NPCC

std 062 Section 2 - Applicability, R2-1: Why are Western and ERCOT Interconnections excluded?

Guy Zito – NPCC and Pete Henderson –IMO

std 062 Section 2 Level of Non Compliance: Level 3"… demand characteristics were not provided on schedule …" shall be read instead of "… demand characteristics were provided on schedule …" .

SAR Comments on M2

Karl A Bryan; US Army Corps of Engineers - Generators

Make sure you have concise enough instructions of what you are after so that the information you gather from those required to submit data results in useable data.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Unclear how the Regional determination of dynamic demand characteristics (II.E.S1.M1) fits in with the Interconnections' determination of dynamic demand characteristics (II.E.S1.M2)

Ray Morella; FirstEnergy

Refer to comments given for II.E.S1.M1.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

This Standard is better suited to be handled separately from the Phase III/IV blackout recommendation Standards. It would take longer to complete than the measure allows.

Also, this Standard should be field tested before being adopted.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This would be expensive and take longer to complete than the measure allows due to the infrequent nature of abnormal frequency conditions.

Brandon Snyder; Duke Energy

The challenge is to keep the flexibility in how the values are determined - as written- could be by load classification (study), by measurement, or by event validation at the system level.

Peter Burke; ATC

Information not be readily available and difficult to obtain. May be able to make generalizations of load characteristics.

Tom Mielnik; MidAmerican Energy

Needs to have the qualification that this is not required for systems not susceptible to instability. This standard should be field tested first.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

There is no agreed upon or approved method to accomplish this. This is more appropriate for a research project than a standard.

Ken Goldsmith; Aliant Energy

Many customers are not willing to share this type of data - may be difficult to document the customers' requirements.

Comments Submitted During Development of Standard on M2

SERC

Recommend that this measurement be deleted and made part of the MMWG/SDDWG Scope.

IIE M3 – Customer (dynamic) demand data

Summary Consideration:
There are three Measures in this series – IIEM1, IIEM2 and IIEM3. These Measures all address dynamic customer demand data.

IIEM1 – Voltage & Frequency Characteristics of Customer Demands
IIEM2 – Determining Dynamic Characteristics of Customer Demands
IIEM3 – Customer (Dynamic) Demand Data

While the objectives of the III.E.M1 through M3 Measures are important to grid reliability, the Drafting Team recommends deleting these Measures because Stakeholders indicated there is currently no accepted method of developing dynamic load characteristics of power system loads. The Drafting Team did not attempt to provide individual responses to the comments submitted on this Measure. Research in this area is ongoing and validated load models are not expected to be available for some time. Establishing Standards now would not be effective since there would be no way to establish if the models provided were accurate, making the associated Measures unenforceable. The Drafting Team recommends that a SAR be submitted for Standards development once there are accurate methods for developing and validating dynamic load models.

V0 Comments on M3
Guy Zito - NPCC and Brandian - ISO-NE

If the Std remains in the Version 0; Delete specific about "Hydro-Quebec Interconnection".

Travis Bessier – TXU

Obligating LSEs to provide data for dynamic load modeling is unrealistic since this type of data is rarely available or realistically obtainable from the LSE.

SAR Comments on M3
Karl A Bryan; US Army Corps of Engineers - Generators

Make sure you have concise enough instructions of what you are after so that the information you gather from those required to submit data results in useable data.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Load Serving Entities may not be equipped to determine dynamic demand characteristics

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Is this Standard better suited to be handled separately (maybe with M1 and M2) from the Phase III/IV blackout-recommendation Standards.

Also, This Standard should be field tested before being adopted.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

There is no agreed upon or approved method to accomplish this. This is more appropriate for a research project than a standard.

Brandon Snyder; Duke Energy

The challenge is to keep the flexibility in how the values are determined - as written- could be by load classification (study), by measurement, or by event validation at the system level.

Peter Burke; ATC

Information not be readily available and difficult to obtain. May be able to make generalizations of load characteristics.

Tom Mielnik; MidAmerican Energy

Needs to have the qualification that this is not required for systems not susceptible to instability. This standard should be field tested first.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

This is difficult because M1 and M2 are impossible.

Ray Morella; FirstEnergy

Refer to comments given for II.E.S1.M1.

Ken Goldsmith; Aliant Energy

How is this to be gathered. Most customers do not have the level of telemetering required to gather the data.

Comments Submitted During Development of Standard on M3

SERC

Recommend that this measurement be made a guide.

If the measurement is retained, the definition of "load-serving entities" may need further clarification from NERC / Regions. Compliance jurisdiction over load-serving entities may need to be addressed in reliability legislation. This measurement may only be enforceable at the transmission provider level. Will the transmission provider have the capability to capture changes that may occur in demand characteristics over time (example: industrial processes)?

IIIA M2 - Redundancy requirements for transmission system protection

Summary Consideration:

The Drafting Team included this Measure in the set of Phase III & IV Measures in error. This Standard was eliminated before the beginning of the V0 development effort. The Drafting Team apologies to those Stakeholders who submitted comments on this Measure.

V0 Comments on Multiple Measures

Paul Arnold BPA

Title should be clarified to add the word Protection (Change Transmission Maintenance and Testing" to Transmission PROTECTION Maintenance and Testing") as this section includes protection maintenance

Mike Gildea – Constellation

THIS HAS NOT BEEN FIELD TESTED PRIOR TO SUCH AN WIDE SCALE IMPLEMENTATION. ADDITIONALLY, LANGUAGE IS NEEDED IN THIS STANDARD THAT EXPLICITLY REQUIRES COMPARABLE TESTING REQURIEMENTS AS WELL AS COMPARABLE SCHEDULING OF TESTING REQUIREMENTS FOR ALL GENERATION IN THE REGION

Brandian ISO-NE and Guy Zito - NPCC

The existing requirement as listed in S3 for III.A.M.3 requiring all "misoperations to be analyzed for cause and corrective operations" seems to have been deleted. The existing requirement only requires having a procedure. Please reintroduce S3.

V0 Comments on M2

Peter Mackin – TANC

On page 4, add "that own transmission protection system equipment" to the Section 2 Applicability box. It is stated later on in the Standard, but it may cause confusion if the first thing anyone sees is just a line saying this is applicable to Transmission Owners and Generator Owners. It is included in the Requirements box. What I am suggesting can be seen in Standard 69 in the Standard Applicability Box and it is less confusing.

Steve Rueckert - WECC

Suggest adding the words "that own transmission protection system equipment" to the Standard Applicability section for Sections 2 and 3. It is stated later on in the Standard (in the Requirements box of sections 2 and 3), but it may cause confusion on the first page if the first thing seen is the indication that it is applicable to Transmission Owners and Generator Owners. This would need to be done for the Applicability Section on sections 2 and 3. Also noted that the Applicability sections for 2 and 3 include Distribution Providers, but Distribution Providers are not identified on the first page with Transmission Owners and Generator Owners.

Consumers

This requirement is changed from IIIA in that the 30-day time frame is now from the event, not from a Region request. 30-days may be insufficient for analysis, field testing, and development of corrective actions following a misoperation, particularly if the misoperation is complex. While the intent of prompt remediation is laudable, the requirement does not allow sufficient time for the proper follow-up actions.

Guy Zito - NPCC and Pete Henderson – IMO

std 063 Sections 1 to 3:It is suggested that revised section on "Applicability" should include the term "Facility" eg transmission "facility" owner to capture the CWC and LDC facilities this applies to.

Ed Davis Entergy

M2-1 – what kind of evidence?

NIPSCO

The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.
Eliminate "Distribution Provider" that owns a transmission protection system.

SPP

Translation fails to capture correctly all protection system owners. It is possible to have a transmission substation owned by a customer. In such a case the transmission owner is not the owner of the transmission protection system and the incorrect translation increases the burden on the transmission owner by making the transmission owner responsible for equipment not owned

SAR Comments on M2

Alan Adamson; NYSRC

See our comment on this measurement under Question 1.

Karl A Bryan; US Army Corps of Engineers - Generators

Be sure that no system is grandfathered in. It was grandfathering in that led to the Westwing substation problems that Arizona Public Service experienced recently.

Ed Davis; Entergy Services

It is my understanding that this measurement no longer exists.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first. It is important that this standard retain the limitations that the specific redundancy reqauirements only apply to new or upgraded system protection and that existing protection systems are reviewed at a regional level.

Raj Rana; AEP

What specific facilities require redundancy may be difficult to explicitly define.

Gerald Rheault; Manitoba Hydro

Cost implications of this requirement may cause problems in obtaining concensus on this issue.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

Parts A and B should be split into separate measures and templates, one applicable to transmission owners and one to regions.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Recommend the measurement be revised by adding the following to the transmission or protection system owners requirements: “Documentation of the planned implementation of the redundancy requirements should be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request.”

Recommend that parts A (transmission or protection system owners) and B (Regions) be split into two separate measurements / compliance templates.

John Horakh; MAAC

Difficult to determine how much redundancy is required

ISO/RTO Council (9) (Michael Calimano; NYISO) (Peter Henderson; IESO) (Kathleen Goodman; ISO-NE)

Each region should have analysis or specific requirements to make redundancy requirements clear.

John Mulhausen; FP&L

Common communication channels, single battery banks and non-redundant potential transformers represent points of contention.

Doug Hils; Cinergy

Recommend eliminating this standard. If performance requirements of Table I.A are not met then transmission owner should have flexibility to use any available solution and not be restricted to redundant system protection components.

Ray Morella; FirstEnergy

Change the word Redundancy to Backup.

IIIB – Transmission Control Devices

Summary Consideration:

There are three measures in this series – IIIBM1, IIIBM2 and IIIBM3.

- IIIB M1 (Transmission Control Device Models and Data) requires assessments of transmission control devices and is a duplication of already approved V0 Standards (TPL-001, TPL-002, TPL-003 and TPL-004). The Drafting Team is recommending that this Measure be deleted, based on Stakeholder comments.
- IIIBM2 (Provision of Models and Data for Control Devices for Use in System Modeling) and IIIBM3 (Periodic Review of Settings and Operating Strategies of Control Devices) were merged and translated into a single new Standard, MOD-028-1 (Provision of Models and Data for Transmission Power Electronic Control Devices).

The new Standard supports the intent of the original Measures which is to ensure that accurate transmission Power Electronic Control Device models and data are provided to the Transmission Planner. Comments indicated some confusion about what constitutes a ,'Control Device' and the Drafting Team modified the term to, 'Power Electronic Control Devices' with the following definition:

> Fast-acting, electronically operated transmission network elements, such as HVDC and FACTS facilities used for dynamic control of real and reactive power flows, voltages, and other system parameters. Protective relays, generator automatic voltage regulators and other generator controls are not Power Electronic Control Devices.

V0 Comments on Multiple Measures:

Bob Millard – MAIN

> This entire standard should not move forward in Version 0 since it is essentially already covered by Version 0 STD 051. Not well defined and/or detailed, needs further drafting for implementation. Consideration should be given to incorporating this into STD 051 for added emphasis.

IIIBM1 was deleted because it requires an 'assessment' and is already addressed in TPL-001, TPL-002, TPL-003, and TPL-004. However, the other Measures (IIIBM2 and IIIBM3) address the model data, settings, and operating strategy information and are needed for reliability.

Paul Arnold – BPA

> Applicability: The Transmission Planning and Planning Authority functions should be added to periodic review of settings of control devices since part of this section pertains to studies to be performed.

Model data, settings, and operating strategy information should be provided by the owners or operators of this equipment.

FRCC

> We are not sure if the modeling of relays in stability studies in addition to the traditional coordination of relays in a five-year cycle is a reasonable expectation.

Agree. The Drafting Team defined, Power Electronic Control Devices in a way that excludes protective relays.

MAPP Planning Standards Subcommittee

> Applicability: Listed as "Transmission Owners". Yet Applicability varies by section. Add "Planning Authority", "Transmission Planner", "Regional Reliability Council", and "Transmission Operator".

IIIBM1 was deleted because it requires an 'assessment' and is already addressed in TPL-001, TPL-002, TPL-003, and TPL-004 so the "Planning Authority", "Transmission Planner", "Regional Reliability Council" should no longer be responsible for any portion of this Standard. The Transmission Operator was added as a Responsible Entity.

IIIB M1 – Assessment of reliability impact of transmission control devices

Summary Consideration:

IIIB M1 (Assessment of Transmission Control Devices) is a duplication of already approved V0 Standards (TPL-001, TPL-002, TPL-003 and TPL-004) and has been removed from the set of Standards being moved forward for approval. The Drafting Team did not attempt to provide individual responses to the comments submitted on this Measure.

V0 Comments on M1:

MAPP Planning Standards Subcommittee

Revise who is responsible. The requirement indicates Transmission Owner while the Applicability Section says the Planning Authority and the Transmission Planner. Maybe all three apply. Revise the Requirement and the Applicability section to be consistent.

Ed Davis – Entergy

Section 1 - Applicability should include Transmission Owners
Compliance Monitoring "On Request" within 30 days not addressed in the Standard which was included in the original Planning Standard.

SAR Comments on M1:

Ed Davis; Entergy Services

Development of this standard will be viewed upon by many as a new requirement, and will likely face stiff opposition. Also, the applicability may be better suited to someone in a planning role.

Raj Rana; AEP

This appears redundant with table 1 . Is this needed?

Brandon Snyder; Duke Energy

What is the definition of control devices? We would normally review settings and the impact on interconnections.

Peter Burke; ATC

May be better addressed by enhancing I.A. standards; please see comments to Q.2.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

"Transmission Control Devices" needs to be clearly defined

Ray Morella; FirstEnergy

What is considered to be included in transmission control devices? Are these devices that operate for non-fault conditions and are designed to keep the system in a normal stable condition such as FACTS devices, SVCs, transformer LTCs? Does this include automatic reclosing schemes for circuit breakers?

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE) (SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC))

This measure describes the planning process which is already required for all transmission elements (Standards I.A). The distinction between transmission control devices and other transmission elements seems insufficient to warrant a separate measurement. Recommend that this measurement be eliminated.

Comments Submitted During Development of Standard on M1

SERC

This measure describes the planning process for all new or modified transmission elements. The distinction between transmission control devices and other transmission elements seems insufficient to warrant a separate measurement. Recommend that this measurement be converted to a guide.

IIIB M2 –Transmission control device models and data

Summary Consideration:

IIIBM2 (Transmission Control Device Models and Data) and IIIBM3 (Periodic review & validation of settings & operating strategies) were merged and translated into a single new Standard, MOD-028-1 (Provision of Models and Data for Transmission Power Electronic Control Devices). The new Standard supports the intent of the original Measures which is to ensure that accurate transmission Power Electronic Control Device models and data are provided to the Transmission Planner.

- Several Stakeholders indicated that the term, 'Transmission Control Devices' needs to be defined. The Drafting Team replaced, 'Transmission Control Devices' with the more explicit term, ''Transmission Power Electronic Control Devices' to clarify what equipment should be addressed in this new Standard. The Drafting Team provided a definition of this new term for consideration by Stakeholders:

  > Fast-acting, electronically operated transmission network elements, such as HVDC and FACTS facilities used for dynamic control of real and reactive power flows, voltages, and other system parameters. Protective relays, generator automatic voltage regulators and other generator controls are not Power Electronic Control Devices.

SAR Comments on M2

Ed Davis; Entergy Services

The applicability may be better suited to someone in a planning role.

Under the Functional Model, the owner is responsible for providing this information.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.

The Drafting Team is not recommending this Standard be field tested because the measure is asking for data that is already being provided by entities who own transmission Power Electronic Control Devices.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

"Transmission Control Devices" needs to be clearly defined

Agree. The Drafting Team changed the term to 'Power Electronic Control Devices' and provided a definition as suggested.

Doug Hils; Cinergy

This measure requires submittal of data to model the transmission control device. Modeling data is covered in Version 0 standard 058.2 (Steady-state data) and 058.3 (Dynamics data) so this standard should be eliminated.

The data to be provided for modeling under the MOD-010 through MOD-013 Standards is not as specific as the data required in this standard.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE) (SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

This measure describes the modeling and data submittal process which is already required for all transmission elements (Standards I.A). The distinction between transmission control devices and other transmission elements seems insufficient to warrant a separate measurement. Recommend that this measurement be eliminated.

While the submittal of steady state and dynamic equipment characteristics that was required in II.A.S1. M2 and II.A.S1.M3 partly addresses appropriate modeling of transmission Power Electronic Control Devices, these devices have special modeling and data variations that put them in a category similar to Generator Equipment, the additional requirements of which II.A.S1.M6 states are included another Standard (e.g. II.B).

Ray Morella; FirstEnergy

> What is considered to be included in transmission control devices? Are these devices that operate for non-fault conditions and are designed to keep the system in a normal stable condition such as FACTS devices, SVCs, transformer LTCs? Does this include automatic reclosing schemes for circuit breakers?

These devices are Power Electronic Control Devices (e.g. SVCs, HVDCs, and STATCOMs). A definition of these devices has been developed and will be added to the NERC Glossary for Reliability Standards.

Comments Submitted During Development of Standard on M2

SERC

> This measure describes the modeling and data submittal process for all transmission elements. The distinction between transmission control devices and other transmission elements seems insufficient to warrant a separate measurement. Recommend that this measurement be converted to a guide.

The submittal of steady state and dynamic equipment characteristics that was required in II.A.S1. M2 and II.A.S1.M3 partly addresses appropriate modeling of transmission Power Electronic Control Devices. These devices have special modeling and data variations that put them in a category similar to Generator Equipment, the additional requirements of which II.A.S1.M6 states are included in another Standard (e.g. II.B).

IIIB M3 – Periodic review & validation of settings & operating strategies

Summary Consideration:

IIIBM2 (Transmission Control Device Models and Data) and IIIBM3 (Periodic review & validation of settings & operating strategies) were merged and translated into a single new Standard, MOD-028-1 (Provision of Models and Data for Transmission Power Electronic Control Devices). The new Standard supports the intent of the original Measures which is to ensure that accurate transmission Power Electronic Control Device models and data are provided to the Transmission Planner.

- Several Stakeholders indicated that the term, 'Transmission Control Devices' needs to be defined. The Drafting Team replaced, 'Transmission Control Devices' with the more explicit term, ''Transmission Power Electronic Control Devices' to clarify what equipment should be addressed in this new Standard. The Drafting Team provided a definition of this new term for consideration by Stakeholders.
- Several Stakeholders indicated that there may be a great deal of work in complying with this Measure – however, as envisioned if the annual Transmission Planning assessments in TPL-001, TPL-002, TPL-003, and TPL-004, include the Power Electronic Control Devices, this requirement will be met.

V0 Comments on M3

MAPP Planning Standards Subcommittee

The requirement indicates that the Transmission Owner and Transmission Operator are responsible. Yet the Applicability Section and Measures indicates only Transmission Owners. Add Transmission Operator to Applicability and Measures.

The Transmission Operator was in the original Measure and was returned as suggested.

Ed Davis Entergy

Section 3 - Applicability should include Transmission Operator

The Transmission Operator was in the original Measure and was returned as suggested.

SAR Comments on M3

Ed Davis; Entergy Services

The applicability may be better suited to someone in a planning role.

The Transmission Owners and Operators have models and data for the equipment they own and operate and the Transmission Owners and Transmission Operators provide the models and data to the Transmission Planner. Because this Standard focuses on providing models and data from the equipment, the Transmission Planner was added as the recipient of the models and data, but wasn't added as a provider of models and data.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

Recommend that this measurement be eliminated. See comments for III.B.M1 and M2

Many Stakeholders indicated that IIIBM1 should be eliminated, but most Stakeholders seemed to accept IIIBM2 with suggested changes.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

"Transmission Control Devices" needs to be clearly defined

Please see the summary consideration.

Peter Burke; ATC

Challenge is to arrive at a consensus on the frequency of review/validation.

Please see the summary consideration.

Brandon Snyder; Duke Energy

This will be extremely difficult. We do not have a program in place to periodically review and validate settings. We only review settings on misoperations or in association with system upgrades. If there is a requirement to perform this every five years we will not be able to comply given the present staffing restrictions.

This will be quite labor intensive and costly from an O&M perspective.

Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

This standard should be field tested first.

A qualification should be added to allow an initial 10 year transition to fully implementation of the standard.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.
Please see the summary consideration.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Recommend that this measurement be eliminated. See comments for III.B.M1 and M2.

Many Stakeholders indicated that IIIBM1 should be eliminated, but most Stakeholders seemed to accept IIIBM2 with suggested changes.

Comments Submitted During Development of Standard on M3

SERC

Recommend the following revisions be made.

The transmission owners or operators shall document and periodically (when required by a change in system conditions, but at least every five years) review the settings and operating strategies of the control devices. Documentation of the current settings and operating strategies shall be provided to the Regions and NERC on request (within 30 days).

The review of settings and operating strategies of the control devices should be done when required by a change in system conditions, but at least every five years.

Per the comments on III.B.S1.M1&M2, propose that this measurement become M1, and that the existing M1 and M2 be converted to guides in III.B.

Please see the summary consideration.
The new Standard adopts the intent of your suggested changes to the requirements and measures.

IIIC – System Protection & Control

Summary Consideration:

There are 12 Measures in this series – IIICM1 through IIICM12. All of the Measures were translated into Standards – several Measures were merged into already approved Version 0 Standards – several Measures were merged together into new Standards.

- IIICM1 (Operation of all Synchronous Generators in the Automatic Voltage Control Mode - Documentation), IIICM3 (Generator Operation for Maintaining Network Voltage Schedules - Documentation), and IIICM5 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Documentation) were merged into the already approved VAR-001-1 (Voltage and Reactive Control).
- IIICM2 (Operation of All Synchronous Generators in the Automatic Voltage Control Mode - Data), IIICM4 (Generator Operation for Maintaining Network Voltage Schedules - Data) and IIICM6 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Data), were merged into a new Standard, VAR-002-1 (Generator Operation for Maintaining Network Voltage Schedules.
- IIICM7 (Generators Performance during Temporary Excursions) was translated into new Standard, VAR-004-1 (Generators Performance curing Temporary Frequency and Voltage Excursions).
- IIICM8 (Coordination of Generator Controls with the Generator's Short-Term Capabilities and Protective Relays) was translated into new Standard, PRC-019-1 (Coordination of Generator Controls with Generator Capabilities).
- IIICM9 (Speed/Load Governing System) was merged with IIBM5 (Test Results of Speed/Load Governor Controls) into a new Standard, MOD-027-1 (Verification and Status of Generator Frequency Response).
- IIICM10 (Regional Procedure on Generator Protection Operations) was merged into the already approved Standard, PRC-003-1 (Regional Procedure for Transmission and Generation Protection System Misoperations).
- IIICM11 (Analysis of Misoperations of Generator Protection Equipment) was merged into the already approved Standard, PRC-004-1 (Analysis and Reporting of Transmission and Generation Protection System Misoperations).
- IIICM12 (Maintenance and Testing of Generator Protection Systems) was merged into the already approved Standard, PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing).

During the field testing of some of these Planning Measures, objections were raised concerning the sole reliance upon generator testing for many of these Measures. Many Stakeholders indicated that testing isn't the only valid method of verifying accuracy of models and data and suggested revisions that emphasis 'verification' (the desired result) rather than 'testing' (a method for reaching the desired result). The Drafting Team translated these measures so they preserve the intent of verifying accuracy of models and data without requiring generator testing. This should make the set of proposed Standards more acceptable to the Stakeholders.

Note that the VAR-001-0 was applicable to both the Transmission Operator and the Generator Operator. Most of the requirements were assigned to the Transmission Operator, with only one requirement - to notify the Transmission Operator of the status of generation reactive power sources (out of a total of ten requirements), assigned to the Generator Operator. The new Measures from this IIIC series are almost all assigned to the Generator Operator, and some of them include requirements related to generator reactive power sources. To keep related requirements together without making any of the existing Standards too long, the Drafting Team moved Requirement 9 from VAR-001 to new Standard VAR-002.

V0 Comments on Multiple Measures:

Paul Arnold – BPA

Applicability: The Transmission Planning and Planning Authority functions should be added for the network voltage determination and studies required.

The IIIC Measures were applicable to Regional Reliability Organizations, Transmission Operators, Generator Owners and Generator Operators. During the translation, none of the translated Measures was assigned to the Transmission Planner or the Planning Authority.

Mike Gildea - Constellation

THIS HAS NOT BEEN FIELD TESTED PRIOR TO SUCH AN WIDE SCALE IMPLEMENTATION. ADDITIONALLY, LANGUAGE IS NEEDED IN THIS STANDARD THAT EXPLICITLY REQUIRES COMPARABLE TESTING REQURIEMENTS AS WELL AS COMPARABLE SCHEDULING OF TESTING REQUIREMENTS FOR ALL GENERATION IN THE REGION

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis.
Please see the summary consideration.

SPP

Standard 065 - III.C.M7 should be extensively revised because it is so vague. The NERC IDWG was unable to evaluate any Region using the October 2000 compliance template.

Please see the summary consideration.

Comments Submitted During Development of Standard on Multiple Measures:

WECC

III.C.S2.M5-6 – With suggested changes incorporated, the requirements from these two measurements could be merged into measurements 3 & 4, resulting in these two measurements as stand alone items being deleted.

The Drafting Team did merge some of the requirements – measures 1, 3 and 5 were merged into existing VAR-001. Measures 2, 4 and 6 were merged with existing VAR-002.

IIIC M1 – Procedure for reporting operation w/out auto voltage control mode

Summary Consideration:

IIICM1 (Operation of all Synchronous Generators in the Automatic Voltage Control Mode - Documentation), IIICM3 (Generator Operation for Maintaining Network Voltage Schedules - Documentation), and IIICM5 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Documentation) were merged into the already approved VAR-001-1 (Voltage and Reactive Control).

- The turnaround time for producing requested documentation was changed from 5 days to 30 calendar days. All of the V0 Planning Standards were modified to indicate that the turnaround time for providing documentation would be either 'five business days' or '30 calendar days'. These default time periods have been adopted for use with Version 1 Planning Standards. The response time can be different if there are unique requirements for reporting.

- Note that the VAR-001-0 was applicable to both the Transmission Operator and the Generator Operator. Most of the requirements were assigned to the Transmission Operator, with only one requirement - to notify the Transmission Operator of the status of generation reactive power sources (out of a total of ten requirements), assigned to the Generator Operator. The new Measures from this IIIC series are almost all assigned to the Generator Operator, and some of them include requirements related to generator reactive power sources. To keep related requirements together without making any of the existing Standards too long, the Drafting Team moved Requirement 9 from VAR-001 to new Standard VAR-002.

- To address one of the Stakeholder comments about keeping Nuclear Power Plant Operators informed of changes the following requirement was added to the Standard:
    - When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall notify the Generator Operator of a voltage schedule or reactive output to maintain Interconnection and generator stability.

- Several Stakeholders indicated they felt that M1 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM1. IIICM1 requires the Transmission Operator to have procedures requiring each Generator Operator with one or more synchronous generators connected to its system to provide information relative to operating in the automatic mode. VAR-001 does not contain any similar requirements.

The proposed VAR-001-1 and VAR-002-1 Standards work together – in VAR-001-1 the Transmission Operator is required to have procedures that address operating requirements and exchange of information with the Generator Operator and in VAR-002-1 the Generator Operator is required to operate to those requirements and to provide the identified information. The tone of these proposed Standards reflects 'cooperation' rather than 'command and control' and reflects the Generator Operator's need to act to protect its equipment. While the source Measures required the Generator Operator to obtain the Transmission Operator's 'approval' the proposed Standards require the Generator Operator to obtain the Transmission Operator's 'concurrence'. This change supports comments submitted from Stakeholders.

V0 Comments on M1:

MAPP Planning Standards Subcommittee

> Providing information "upon request" sometimes means 5 business days or 30 business days. This abnormality should be consistent when using "upon request". The same issue occurs in other places within 065.
> Whose procedures are being referenced here? R1-2 should begin as "The Transmission Operator's procedures

Please see the summary consideration. Upon request has been clarified as '30 business days'. The suggestion to clarify that the procedures are the Transmission Operators was adopted and is reflected in the proposed Standard.

SPP

The translation of levels of non-compliance errantly omits "synchronous" in the reference to procedures. There is a distinct difference between synchronous and asynchronous generators and "synchronous" must be included.

Reviewed and inserted 'synchronous' where applicable in the requirements and measures. The levels of non-compliance refer to the requirement.

SAR Comments on M1:

Karl A Bryan; US Army Corps of Engineers - Generators

This should be more of an administrative reporting process. The big problem is making sure that the reported information gets cranked into the studies and the outage coordination process.

Agree.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Need to make clear that the timeframe in which the Transmission Operator's procedures are due to the Regional Reliability council is "On request (five business days)".

Please see the summary consideration. Upon request has been clarified as '30 business days'.

Need to make clear that the timeframe in the Transmission Operator's procedure that the Generator Operators are required to provide the required information is "on request (five business days)" or should this be "on request (thirty business days)" as specified in III.C.M2.

The reporting time limit was removed from this requirement, since it is a requirement best left to the individual Transmission Operators and Generator Operators.

Peter Burke; ATC

Development of procedure should not be difficult.

Agree.

Brandon Snyder; Duke Energy and Christopher Schaeffer; Duke Energy

May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control.

The SERC GS has expressed concerns that this standard has not been fully developed and does not address actions the transmission system operator must take to assure nearby generator operation in manual does not adversly affect the ablity of the grid to support nuclear switchyard voltage requirements.

Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Revisions need to be made based upon comments generated by field testing the standard.

Please see the summary consideration.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

John Horakh; MAAC (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Allow procedure to be only that Generation Owner/Operator reports when not in automatic voltage control mode, Transmission Operator keeps and analyzes data

Agree.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing. May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control.

Please see the summary consideration.

The Drafting Team has reviewed the comments from the field testing phase and incorporated the clarifications as appropriate.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control. There are concerns that this standard has not been fully developed and does not address actions the transmission system operator must take to assure nearby generator operation in manual does not adversly affect the ability of the grid to support nuclear switchyard voltage requirements.

Please see the summary consideration.

Comments Submitted During Development of Standard on M1

SERC

Recommend that this measurement be revised as indicated below:

M1. Transmission system operators shall have procedures (available within five business days) requiring synchronous generator owners/operators to provide the following information to them, the Region, and NERC on request:

Please see the summary consideration.

IIIC M2 – Log of operation without automatic voltage control mode by gen owner

Summary Consideration:

IIICM2 (Operation of All Synchronous Generators in the Automatic Voltage Control Mode - Data), IIICM4 (Generator Operation for Maintaining Network Voltage Schedules - Data) and IIICM6 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Data), were merged into a new Standard, VAR-002-1 (Generator Operation for Maintaining Network Voltage Schedules.

Several Stakeholders indicated they felt that M2 is redundant with VAR-001. The Drafting Team reviewed the requirements of VAR-001 and IIICM2. VAR-001 contains a requirement for the Generator Operator to provide information to its Transmission Operator on the status of its reactive power resources – and IIICM2 requires the Generator Operator to operate its synchronous generating units in the automatic voltage control mode unless otherwise approved by the Transmission Operator. These are two different requirements, so the Drafting Team did not remove IIICM2 from the set of Standards being moved forward for approval.

The proposed VAR-001-1 and VAR-002-1 Standards work together – in VAR-001-1 the Transmission Operator is required to have procedures that address operating requirements and exchange of information with the Generator Operator and in VAR-002-1 the Generator Operator is required to operate to those requirements and to provide the identified information. The tone of these proposed Standards reflects ‘cooperation’ rather than ‘command and control’ and reflects the Generator Operator’s need to act to protect its equipment. While the source Measures required the Generator Operator to obtain the Transmission Operator’s ‘approval’ the proposed Standards require the Generator Operator to obtain the Transmission Operator’s ‘concurrence’. This change supports comments submitted from Stakeholders.

V0 Comments on M2

Bob Millard – MAIN

> This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 065, Section 1.

Version 0 Standard 065 (IIICM1) did not move forward in Version 0.

MAPP Planning Standards Subcommittee

> The last part of the sentence (phrase "to be reviewed to verify compliance with this Reliability Standard") can be deleted.

This phrase was removed as suggested.

SAR Comments on M2

Karl A Bryan; US Army Corps of Engineers - Generators

> This should be easy for the generation owner to add to his equipment SCADA recording and then forwarding the information onto the TSP or BA.

The Standard does not address the specific method for recording and reporting data.

Tom Mielnik; MidAmerican Energy

> Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Brandon Snyder; Duke Energy

> May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control.
> We believe a log should be maintained by the system operator stating when the report was made and that continued operation in manual does not affect system stability nor adversely affect nuclear switchyerd voltage requirements. If one of these is threatened, the operator should also document what actions were taken to address.

The requirement in VAR-002 for the Generator Operator has been modified so the Generator Operator must make its logs available on request. Transmission Operator requirements for logging are addressed in VAR-001. VAR-001 was modified to clarify that the Transmission Operator is required to notify the Generator Operator of a voltage schedule or reactive output to support system and generator stability.

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Peter Burke; ATC

Getting generator owner to record the information may be the difficult task.

Recording the status of the voltage regulating equipment is important for reliable operation.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Need to make clear that the timeframe in the Transmission Operator's procedure that the Generator Operators are required to provide the required information is "on request (thirty business days)" or should this be "on request (five business days)" as specified in III.C.M1.

This time requirement was removed from VAR-001 to give the Transmission Operators and Generator Operators a bit of latitude in specifying whatever time period is best for them.

Basing the levels of non-compliance on "X unithours, without permission from the Transmission Operator" may be difficult to achieve consensus (from Generator Operators) on X values for various levels. Basis for levels of non-compliance may need to account for the number and size of generators an entity operates.

The proposed Standard does not require the Generator Operator to obtain 'permission' from the Transmission Operator. Reliability Standard VAR-001-1 requires the Transmission Operator to have procedures for Generator Operators who operate synchronous generators within its area. These procedures must specify criteria by which generators are exempt from certain reporting requirements.

The standard and measurement should be revised to reflect the fact that generation stations must have the right to determine when continued operation in Automatic controls is not desirable (such as during regulator failures) to protect the unit. This requirement should be rewritten to state that prior approval of the system operator is not required in pre-defined circumstances. In these circumstances the standard/measurement should provide requirements for a timely notification from the plant to the system operator that the switch to manual has occurred.

The generator is not required to take actions that would cause a safety risk or equipment damage, or violate a statute or regulation.

This suggestion seems like the type of language that belongs in a formal agreement between the Transmission Operator and the Generator Owner/Operator.

Christopher Schaeffer; Duke Energy

May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control.

Believe a log should be maintained by the system operator stating when the report was made and that continued operation in manual does not affect system stability nor adversely affect nuclear switchyerd voltage requirements. If one of these is threatened, the operator should also document what actions were taken to address.

VAR-002-1_R1.3 and VAR-002-1_M2 require the Generator Operator to report to its Transmission Operator the date, time, duration, and reason for each period when a synchronous generator was not operated in the automatic voltage control mode and requires that this notification be documented in a log that must be made available upon request.

John Horakh; MAAC (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

There is an incentive not to report, and penalties for a larger number of reported incidents

Please see the summary consideration.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

Present compliance levels puts a company into non-compliance if this standard is not met for a second. If the notification is not made before the event one could be in non-compliance. The standard should have some deadband in response time.

Please see the summary consideration.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

Most of the opposition to the IIIC Measurements seemed to be related to generator testing, and the proposed Standards do not require this.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing. May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control.

Please see the summary consideration.

The Drafting Team has reviewed and incorporated changes from the field testing comments.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

May be redundant with Operations Standard VAR-001-0 — Voltage and Reactive Control. Not sure there is a reliability reason for the generator owner to log these events. It would make more sense for the Transmission Operator to log and evaluate these events and also document if any actions was required or taken to protect the transmission system reliability.

Please see the summary consideration.

Comments Submitted During Development of Standard on M2

MAAC

While not excluded, MAAC chose to meet this measurement by keeping a region-wide log at the PJM Control Center. Mentioning this option in the measurement should be considered. MAAC is utilizing a web-based reporting product developed by PJM called eDart. The logs can easily be produced from the eDart database.

The Standard does not address 'how' the requirement is met, but the Generator Operator is still accountable for recording and logging the information.

SERC

The standard and measurement should be revised to reflect the fact that generation stations must have the right to determine when continued operation in Automatic controls is not desirable (such as during regulator failures) to protect against unnecessary trips. This requirement should be re-written to state that prior approval of the system operator is not required in pre-defined circumstances. In these circumstances the standard/measurement should provide requirements for a timely notification from the plant to the system operator that the switch to manual has occurred.

Please see the summary consideration.

SERC MEMBER

Member A : We believe the wording of this standard should be changed to reflect the plant operator's authority to switch to manual [if manual operation is necessary to assure continued operation].

Please see the summary consideration.

It is inappropriate to specify operations requirements and collect plant operating data as part of a planning process. This requirement should be moved to an Operations process.

All the Standards are simply 'Reliability Standards' without distinguishing between 'Operating' and 'Planning.' Please review the proposed Standard – the data that is exchanged between the Generator Operator and the Transmission Operator is used in the 'operations horizon'.

IIIC M3 – Documentation of schedule for maintaining network voltage

Summary Consideration:

IIICM1 (Operation of all Synchronous Generators in the Automatic Voltage Control Mode - Documentation), IIICM3 (Generator Operation for Maintaining Network Voltage Schedules - Documentation), and IIICM5 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Documentation) were merged into the already approved VAR-001-1 (Voltage and Reactive Control).

VAR-001 did contain the following requirement for the Generator Operator:

R9 Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.

R9.1 When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.

Stakeholders noted that the original Measure called for the Generator Operator to notify the Transmission Operator of the loss of an Automatic Voltage Regulator (AVR), but didn't include a specific time period for making this notification - and the associated Levels of Non-compliance assigned a sanction if any time passed before the notification occurred. The Drafting Team included language in VAR-002-1_R1.1 to indicate that the Generator Operator has to notify the Transmission Operator within 30-minutes of the loss of an AVR.

Based on Stakeholder comments, this requirement was moved to VAR-002-1 and renumbered with the modifications shown below:

R1.1. Each Generator Operator shall ~~provide information to~~ inform its Transmission Operator within 30 minutes of a change of a ~~on the~~ status ~~of all~~ on any ~~generation~~ synchronous generator reactive power resource~~s~~, including the status of voltage regulator~~s~~ and power system stabilizer~~s~~.

R1.2. When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.

Conforming changes were made to the Levels of Non-Compliance so that it is clear that the Generator Operator has 30 minutes to notify the Transmission Operator of a change in status of a synchronous generator.

The proposed VAR-001-1 and VAR-002-1 Standards work together – in VAR-001-1 the Transmission Operator is required to have procedures that address operating requirements and exchange of information with the Generator Operator and in VAR-002-1 the Generator Operator is required to operate to those requirements and to provide the identified information. The tone of these proposed Standards reflects 'cooperation' rather than 'command and control' and reflects the Generator Operator's need to act to protect its equipment. While the source Measures required the Generator Operator to obtain the Transmission Operator's 'approval' the proposed Standards require the Generator Operator to obtain the Transmission Operator's 'concurrence'. This change supports comments submitted from Stakeholders.

SAR Comments on M3

Peter Burke; ATC

Documentation of such schedule should be simple task.

Agree.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers) and Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing.

The Drafting Team has reviewed the field testing comments and incorporated revisions as appropriate.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Agree. This was changed to '30 calendar days.'

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Comments Submitted During Development of Standard on M3

WECC

(Document Voltage/Reactive Schedules) – The M3 measurement should be modified to require the transmission operator to specify a desired system voltage/reactive target, with the specifics of the target left to the transmission operator. Some transmission operators do not specify voltage/reactive targets by individual bus, but by system requirements including voltage ranges for specific buses or voltage level of buses. WSCC suggests that the M3 measurement drop the words "at a specified bus", so that the measurement reads:

VAR-001_R3 requires the Transmission Operator to provide voltage schedules for synchronous generators, but does not say the schedule has to be a specific number. For the rest of the system, there is no requirement to specify the voltage at each bus, only to maintain voltage within limits (see requirement 7).

"Each transmission system operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator and shall provide this information to the generator owner/operator. Documentation of the information provided to the generator owner/operator shall be provided to the Region and NERC on request."

The requirement of the second paragraph for each transmission system operator to maintain a list of exempt generators is over burdensome and does not contribute to bulk system reliability. This second paragraph should be deleted.

Knowing which generators are exempt from voltage scheduling is important to reliability.

SERC

Recommend the first paragraph of the measurement be revised as follows:

M3. Each transmission system operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Generator voltage or reactive schedule shall recognize generator design characteristics as well as other operational and regulatory limitations. Documentation of the information provided to the generator owner/operator shall be provided to the Region and NERC on request (five business days).

VAR-001-1_R3 states "within generator reactive capability".

IIIC M4 – Log operation not maintaining network voltage schedules

Summary Consideration:

IIICM2 (Operation of All Synchronous Generators in the Automatic Voltage Control Mode - Data), IIICM4 (Generator Operation for Maintaining Network Voltage Schedules - Data) and IIICM6 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Data), were merged into a new Standard, VAR-002-1 (Generator Operation for Maintaining Network Voltage Schedules.

Stakeholders also indicated that the original Measure didn't allow the Generator Operator a defined time period for notifying the Transmission Operator of a change in the unit and didn't reflect the Generator Operator's need to have some input into the decisions made about the operation of its equipment. The proposed Standard gives the Generator Operator a 30-minute window in which to notify the Transmission Operator of the loss of automatic voltage regulation and for the generator operator and transmission operator to 'concur' on a manually controlled voltage level or reactive output. Conforming changes were made to the language in the levels of non-compliance.

The proposed VAR-001-1 and VAR-002-1 Standards work together – in VAR-001-1 the Transmission Operator is required to have procedures that address operating requirements and exchange of information with the Generator Operator and in VAR-002-1 the Generator Operator is required to operate to those requirements and to provide the identified information. The tone of these proposed Standards reflects 'cooperation' rather than 'command and control' and reflects the Generator Operator's need to act to protect its equipment. While the source Measures required the Generator Operator to obtain the Transmission Operator's 'approval' the proposed Standards require the Generator Operator to obtain the Transmission Operator's 'concurrence'. This change supports comments submitted from Stakeholders.

V0 Comments on M4

Bob Millard MAIN

> This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 065, Section 3.

Version 0's Standard 065 was removed from the set of Standards that was moved forward for approval.

Consumers

> The wording "within the reactive capability of the units" should be kept in R4-1. Also, the Levels of Non Compliance are too extreme. There should be some "grace" period prior to being at Level 1 and there should be larger ranges between each Level.

The proposed Standard includes the phrase, 'within limits' rather than the phrase, 'within the reactive capability of the units'. The levels of non-compliance have been modified to conform to the changes made in the requirements and measures. The proposed levels of non-compliance should be less extreme than those associated with the original Measure. Note that a 'grace period' of 30 minutes was added to give the Generator Operator time to notify the Transmission Operator.

Ameren

> Measurement M4 from the existing standard, which requires generator owners to provide operating characteristics of generator's equipment and protective relays and controls, was not carried over to the new standard. We do not agree that the guides should be eliminated, as they contain many critical items that are explained as "good utility practice", which we have referenced in parallel operating agreements.

This appears to be a reference to M8, which is being developed in a protection standard.

Elimination of Guides was addressed during the development of V0 Standards.

SAR Comments on M4

Christopher Schaeffer; Duke Energy
Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)
Brandon Snyder; Duke Energy

Not sure there is a reliability reason for the generator owner to log these events. It would make more sense for the grid operator to evaluate out of band operation and also document any actions taken to adjust.

Having information when generators are out of schedule is important to reliability. The Transmission Operator must get this information from the Generator Operator and therefore the Generator Operator must record and log the information. The log validates that the communications took place as required.

Peter Henderson; IESO

There is an incentive not to report, and penalties for a larger number of reported incidents

If the log is incomplete, the lowest level of non-compliance is Level 3. The generator can report off-schedule operations up to 16 hours and remain within Level 2 violations. There is an incentive for the generator operator to get concurrence to change the voltage schedule, since the violation can be avoided if concurrence is given.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Raj Rana; AEP

Determination of non-compliance may be an issue

The Drafting Team does not have enough information from the comment to understand the concern.

Peter Burke; ATC

Getting system operator to record the information may be the difficult task.

Having information when generators are out of schedule is important to reliability. The Transmission Operator must get this information from the Generator Operator and therefore the Generator Operator must record and log the information. The log validates that the communications took place as required.

Karl A Bryan; US Army Corps of Engineers - Generators

First issue would be to define what a violation of a voltage schedule is.

The parameters of the voltage schedule are determined by the Transmission Operator. If the generator operates outside the parameters of the schedule, then it is not meeting the schedule.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Basing the levels of non-compliance on "X unithours, without permission from the Transmission Operator" may be difficult to achieve consensus (from Generator Operators) on X values for various levels. Basis for levels of non-compliance may need to account for the number and size of generators an entity operates.

Please see the summary consideration. A 'grace period' of 30 minutes was added to allow the Generator Operator time to communicate with the Transmission Operator.

Recommend that the standard and measurement should be revised to reflect the fact that generation stations must have the right to determine when continued operation at a specified voltage or reactive output is not desirable to protect the unit.

The generator is not required to take actions that would cause safety risk or equipment damage, or violate a statute or regulation.

John Horakh; MAAC (ISO/RTO Council (9)) (Michael Calimano; NYISO)

There is an incentive not to report, and penalties for a larger number of reported incidents

If the log is incomplete, the lowest level of non-compliance is Level 3. The generator can report off-schedule operations up to 16 hours and remain within Level 2 violations. There is an incentive for the Generator Operator to get concurrence to change the voltage schedule, since the violation can be avoided if concurrence is given.

Ray Morella; FirstEnergy and Kenneth John Dresner; FirstEnergy Solutions

Present compliance levels puts a company into non-compliance if this standard is not met for a second. If the notification is not made before the event one could be in non-compliance. The standard should have some deadband in response time.

Please see the summary consideration. The Standards do not require a generator to operate so as to cause a safety risk, damage to equipment or to violate statutes or regulations.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

The Drafting Team has reviewed the field testing comments and incorporated revisions as appropriate.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing.

The Drafting Team has reviewed the field testing comments and incorporated revisions as appropriate.

Comments Submitted During Development of Standard on M4

MAAC

As above in M2, MAAC chose to meet this measurement by keeping a region-wide log at the PJM Control Center.

Agree. Meeting this Measure should be achievable. The Standard does not specify how the log is kept, but does hold the Generator Operator accountable for its log.

SERC MEMBER

Member A : It is inappropriate to specify operations requirements and collect plant operating data as part of a planning process. This requirement should be moved to an Operations process.

All the Standards are simply 'Reliability Standards' without distinguishing between 'Operating' and 'Planning.' Please review the proposed Standard – the data that is exchanged between the Generator Operator and the Transmission Operator is used in the 'operations horizon'.

WECC

(Reporting of Voltage/Reactive Schedule Violations) – The M4 measurement does not specify how long the log must be maintained. How does the existence of such a log improve system reliability?

The compliance section states a rolling 12 months. The complementary Standard, VAR-001-1 includes a requirement that the Transmission Operator have a set of Procedures for its Generator Operators that includes a requirement that the Generator Operator keep its reports off these off-schedule operations for 12 rolling months.

Having information when generators are out of schedule is important to reliability. The Transmission Operator must get this information from the Generator Operator and therefore the Generator Operator must record and log the information. The log validates that the communications took place as required.

WSCC suggests that the requirements for this measurement be modified to require Security Coordinators to keep a log of reliability infractions that jeopardize the reliability of the interconnected system, with current M4 violations, if they jeopardized the reliability of the interconnected system, included as part of the log.

The Reliability Coordinator requirements are addressed in the sequence of Interconnection Reliability Operations and Coordination (IRO) Standards.

SERC

> Recommend that the standard and measurement should be revised to reflect the fact that generation stations must have the right to determine when continued operation at a specified voltage or reactive output is not desirable to protect against unnecessary trips. This requirement should be re-written to state that prior approval of the system operator is not required in pre-defined circumstances. In these circumstances the standard/measurement should provide requirements for a timely notification from the plant to the system operator that the generator is no longer operating at the specified voltage or reactive output.

Please see the summary consideration. The Standards do not require a generator to operate so as to cause a safety risk, damage to equipment or to violate statutes or regulations.

IIIC M5 – Reporting Procedures for tap settings of generator transformers

Summary Consideration:

IIICM1 (Operation of all Synchronous Generators in the Automatic Voltage Control Mode - Documentation), IIICM3 (Generator Operation for Maintaining Network Voltage Schedules - Documentation), and IIICM5 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Documentation) were merged into the already approved Standard, VAR-001-1 (Voltage and Reactive Control).

The proposed VAR-001-1 and VAR-002-1 Standards work together – in VAR-001-1 the Transmission Operator is required to have procedures that address operating requirements and exchange of information with the Generator Operator and in VAR-002-1 the Generator Operator is required to operate to those requirements and to provide the identified information. The tone of these proposed Standards reflects 'cooperation' rather than 'command and control' and reflects the Generator Operator's need to act to protect its equipment. While the source Measures required the Generator Operator to obtain the Transmission Operator's 'approval' the proposed Standards require the Generator Operator to obtain the Transmission Operator's 'concurrence'. This change supports comments submitted from Stakeholders.

V0 Comments on M5

MAPP Planning Standards Subcommittee

The term "Transmission Owner" should be "Transmission Operator" to align with R5-1 within 065.

This correction has been made.

SAR Comments on M5

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

This must take into account extensive comments received in Phase III field testing.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Karl A Bryan; US Army Corps of Engineers - Generators

The difficulty will be in setting up a business process where changes in tap settings are forwarded to the appropriate people and in getting the data base updated.

This does not seem to be a difficult task.

Ken Goldsmith; Aliant Energy

Why is this information needed? They are not modeled in most programs.

Tap positions often are modeled in reliability analysis models.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

The reporting time requirement has been changed to, '30 calendar days.'

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Comments Submitted During Development of Standard on M5

WECC

(Procedures requiring generator owners/operators to provide tap settings, ranges, and impedances for GSU to the transmission system operator) – The M5 measurement should be modified. The transmission operator might not be the appropriate entity to identify required tap changes. This decision may be the responsibility of the generation owner/operator based on operating ranges/limits of their units. The transmission operator might not require the other information if they are not responsible for identifying generator operating alternatives for achieving desired voltage/reactive targets. This measurement should be changed to require documentation that identifies the responsible party for making the operating decisions and documentation that notification was made to the generator owner/operator that a new voltage/reactive target was required.

The Transmission Operator or Generator Operator may both initiate tap changes, with justification. The Generator Operator must inform the Transmission Operator of the change so that the transmission operator is aware of equipment configuration and status for modeling purposes.

SERC

Recommend the measurement be revised as follows:

The transmission system operator shall have procedures requiring synchronous generator owners/operators to provide tap settings, available tap ranges, and impedance data for generator step-up and auxiliary transformers. When tap changes are necessary, the transmission system operator and generator owner/operator shall mutually agree upon the required tap changes and technical justification for these changes. The procedures for reporting the data shall also address generating unit exemption criteria (including any that may apply to nuclear units) and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements.

Documentation of these procedures shall be provided to the Region and NERC on request (available within five business days).

Agree. The language in the Standard was modified to provide for mutual agreement between the transmission operator and generator operator for the tap change.

The reporting time requirement was changed to, '30 calendar days.'

IIIC M6 – Tap settings data of generator step-up & auxiliary transformers

Summary Consideration:

IIICM2 (Operation of All Synchronous Generators in the Automatic Voltage Control Mode - Data), IIICM4 (Generator Operation for Maintaining Network Voltage Schedules - Data) and IIICM6 (Tap Settings of Generator Step-Up and Auxiliary Transformers - Data), were merged into a new Standard, VAR-002-1 (Generator Operation for Maintaining Network Voltage Schedules.

Stakeholders also indicated that the original Measure didn't reflect the Generator Operator's need to have some input into the decisions made about the operation of its equipment. The proposed Standard the generator operator and transmission operator to 'mutually agree' not only on the time period for a tap change, but also on the tap change itself. Conforming changes were made to the language in the levels of non-compliance.

The reporting time in the Measure was '5 days' and this was changed to '30 calendar days' in response to comments from Stakeholders as well as a move towards greater consistency between Standards.

The proposed VAR-001-1 and VAR-002-1 Standards work together – in VAR-001-1 the Transmission Operator is required to have procedures that address operating requirements and exchange of information with the Generator Operator and in VAR-002-1 the Generator Operator is required to operate to those requirements and to provide the identified information. The tone of these proposed Standards reflects 'cooperation' rather than 'command and control' and reflects the Generator Operator's need to act to protect its equipment. While the source Measures required the Generator Operator to obtain the Transmission Operator's 'approval' the proposed Standards require the Generator Operator to obtain the Transmission Operator's 'concurrence'. This change supports comments submitted from Stakeholders.

V0 Comments on M6

Bob Millard MAIN

> This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 065, Section 5.

Version 0 Standard 065 did not move forward for approval.

Consumers

> It should be stated in M6-1 that documentation on tap settings, tap setting changes, available tap ranges and impedance data for auxiliary transformers should only be required if requested by the Transmission Operator. Many Transmission Operators are not modeling auxiliary transformers in loadflow or stability studies.

The requirement has been modified to say 'on request'.

> It should be stated in R6-1 that tap settings, available tap ranges and impedance data for auxiliary transformers should only be required if requested by the Transmission Operator. Many Transmission Operators are not modeling auxiliary transformers in loadflow or stability studies.

The requirement has been modified to say 'on request'.

> The following language should be added at the end of R6-2: "unless the Generator Owner can demonstrate that the requested tap change will put the generating unit at a risk level inconsistent with Good Utility Practice".

Please see the summary consideration. Both VAR-001 and VAR-002 have been modified to recognize the need for mutual agreement to move taps.

MAPP Planning Standards Subcommittee

> The range of available tap setting can be provided from nuclear stations, however the allowable range will be limited by NRC Degraded Grid design requirements.

Please see the summary consideration. As proposed, the Standard requires 'mutual agreement' between the Generator Operator and Transmission Operator on tap changes.

In addition, modifications to the taps at nuclear sites cannot be made until extensive power system analyses are performed. These analyses are required to assure the ability to mitigate an accident are reanalyzed to assure the recommended changes are appropriate. Once these analyses are done, a tap change can be implemented into the station modification process. This process is time consuming due to nuclear safety concerns associated with changing the plant auxiliary system voltage avaialble under accident conditions. Any effort to bypass these programs would subject the plant to NRC scrutiny. This requirement should be rewritten recognizing these limitations.

Please see the summary consideration. As proposed, the Standard requires 'mutual agreement' between the Generator Operator and Transmission Operator on tap changes.

Level 1 of Non-compliance needs to have the reference changed to identify the correct Standard number within this Version 0 posting.

This error is not in the proposed Standard.

SAR Comments on M6

Peter Burke; ATC

Information easy to get if not already available.

Agree.

Raj Rana; AEP

Generator may not agree with the need for a tap change, or the scheduling of the outage to perform the change

Please see the summary consideration.

Karl A Bryan; US Army Corps of Engineers - Generators

The difficulty will be in setting up a business process where changes in tap settings are forwarded to the appropriate people and in getting the data base updated.

This is not an insurmountable problem.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards. Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

The reporting time requirement was changed to, '30 calendar days.'

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This measure relies upon III.C.S2.M5 to determine the time period for changing tap settings and would therefore be difficult to get industry consensus.

The Standard requires coordination but does not specify the timeframe for coordination.

Comments Submitted During Development of Standard on M6

WECC

Similar to the suggestions for M5. The M6 requirements should be modified to require the generator owner/operator to document that the voltage/reactive schedules were maintained as requested, with the operation of the generation and tap adjustments left to the entity responsible for making the decision. As suggested for M4, the Security Coordinators should keep a log of reliability infractions that jeopardize the reliability of the interconnected system, with current M6 violations, if jeopardizing the reliability of the interconnected system, included as part of the log.

The Standard requires coordination of tap changers. The generator operator and transmission operator should have the logs.

SERC

The reporting requirements in the measurement should be revised to 30 business days.

The reporting time requirement has been changed to, '30 calendar days.'

SERC MEMBERS

<u>Member A</u> The range of available tap setting can be provided from nuclear stations, however the allowable range will be limited by NRC Degraded Grid design requirements.

In addition, modifications to the taps at nuclear sites cannot be made until extensive power system analyses are performed. These analyses are required to assure the ability to mitigate an accident are reanalyzed to assure the recommended changes are not inappropriate. Once these analyses are done, a tap change can be implemented into the station modification process. This process is time consuming due to nuclear safety concerns associated with changing the plant auxiliary system voltage available under accident conditions. Any effort to bypass these programs would subject the plant to NRC scrutiny.

This requirement should be rewritten recognizing these limitations.

Please see the summary consideration. As proposed, the Standard requires 'mutual agreement' between the Generator Operator and Transmission Operator on tap changes.

<u>Member B :</u> The tap settings of GSU, and the station auxiliary transformers (SAT) are limited by the station auxiliary system and degraded grid voltage requirements. Modifications to the GSU and SAT taps at nuclear plants cannot be made until an extensive power system analysis is performed. This analysis is required to assure the ability to mitigate an accident and that the recommended changes are appropriate. Once the analysis is completed, a tap change will be implemented through the design change process.

Please see the summary consideration. As proposed, the Standard requires 'mutual agreement' between the Generator Operator and Transmission Operator on tap changes.

<u>Member C :</u> We interpret the second paragraph of Measurement M6 to refer to the procedures in Measurement III.C.S2.M5, rather than a mutually agreed upon time frame as the wording might indicate.

Please see the summary consideration. As proposed, the Standard requires 'mutual agreement' between the Generator Operator and Transmission Operator on tap changes. The timeframe is considered to be part of the mutual agreement.

IIIC M7 – Requirements for withstanding temporary excursions

Summary Consideration:

IIICM7 (Generators Performance during Temporary Excursions) was translated into new Standard, VAR-004-1 (Generators Performance curing Temporary Frequency and Voltage Excursions).

Stakeholders indicated that the source Measure was too vague to measure during Field Testing. The Drafting Team revised the requirements so they are measurable. The proposed Standard requires the Regional Reliability Organization to define specifically what it considers to be 'temporary excursions'. The Drafting Team appreciates that establishing and agreeing upon the proposed requirements will take time but will be of value to system reliability. The implementation plan and effective date for this Standard will need to reflect the level of difficulty and effort needed to come into compliance with the requirements.

V0 Comments on M7

SPP

Standard 065 - III.C.M7 should be extensively revised because it is so vague. The NERC IDWG was unable to evaluate any Region using the October 2000 compliance template.

Please see the summary consideration.

SPP

The translation of levels of non-compliance errantly omits "synchronous" in the reference to procedures. There is a distinct difference between synchronous and asynchronous generators and "synchronous" must be included.

The Region is free to add this qualifier to its list of requirements.

Bob Millard MAIN

This section should not move forward in Version 0 since it is not well defined and/or detailed, needs further drafting for implementation and of value interconnection wide.

Please see the summary consideration.

MAPP Planning Standards Subcommittee

The use of the phrase "temporary exursions in voltage, frequency, and real and reactive power output" seems to lack a clear understanding of just how temporary and how large these excursions may be? More definitive language is necessary in determining the requirements for generators to stay connected to the transmission system.

Please see the summary consideration.

Ed Davis Entergy

Section 7 – how "Temporary"?

Section 7 Levels of Non Compliance – Change "or" to "and" in the last line of Level 1

This comment is no longer applicable.

Raj Rana – AEP

NERC IDWG assessed Regions' compliance to this Standard as part of 2001 Compliance Program. IDWG found this Measurement to be "vague and subject to varied interpretation." Therefore, IDWG did not assess Regions' compliance to this Measurement and recommended that this Standard be "revised to be more clear and objective." (Reference: IDWG Report Dated 10/31/01 to NERC Planning Standards Subcommittee.)

Agree. Please see the summary consideration.

SAR Comments on M7

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Revisions need to be made based upon comments generated by field testing the standard.

The time has been changed to, '30 calendar days.'

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Brandon Snyder; Duke Energy

> SERC is working on a revision to the supplement for this measure. The challenge is the expertise to make good, well founded requirements. And then within the transmission planning entities, the processes that incorporate the necessary checks that validate meeting the requirements. The challenge to overcome is how to establish the requirement and how to test against the requirements. These are substantial efforts.

Please see the summary consideration. Testing is not required in this Standard.

Karl A Bryan; US Army Corps of Engineers - Generators

> Getting a consensus amongst the equipment owners of what they will allow equipment to be stressed to and then getting schedulers/operators to understand the limitations. Plus some limitations are very dynamic.

Agree.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

> Implementation will be a difficult challenge. SERC is working on a revision to the supplement for this measure. The challenge is the expertise to make good, well founded requirements. And then within the transmission planning entities, the processes that incorporate the necessary checks that validate meeting the requirements. The challenge to overcome is how to establish the requirement and how to test against the requirements. These are substantial efforts.

Please see the summary consideration. Testing is not required in this Standard.

Peter Burke; ATC

> Simulation of system may be means to determine requirements, but actual testing may be difficult.

Please see the summary consideration. Testing is not required in this Standard.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

> The standard as written is rather vague. Both Transmission and Generator protection expertise are required to work with the system modeling experts to develop meaningful requirements that can applied.

Please see the summary consideration.

Christopher Schaeffer; Duke Energy

> It's not clear what this is trying to accomplish.

The Standard is an attempt to establish some consistency on when generators will set relay tripping in relation to system conditions.

Ray Morella; FirstEnergy and Kenneth John Dresner; FirstEnergy Solutions

> Defining and agreeing on the "temporary excursions" definitions will be difficult to reach agreement between transmission owners and generation operators. The possiblitiy of testing at these conditions will most likely not be probable.

Agree. The proposed Standard requires the Regional Reliability Organization to define specifically what it considers to be ‘temporary excursions’.

Ed Davis; Entergy Services

> The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.
>
> Without significant rewrite, the III.C measurements will not easily reach consensus.

Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

Excursions in voltage that generators can ride through are extremely difficult to determine.

Please see the summary consideration.

Gerald Rheault; Manitoba Hydro

The requirements in different parts of the US and Canada may be very different based on the load concentration in each region.

Agree. The proposed Standard requires the Regional Reliability Organization to define specifically what it considers to be 'temporary excursions'.

Raj Rana; AEP

It is not possible to measure the compliance to this Measurement because it is vague and subject to varied interpretation. Therefore, NERC IDWG did not assess Regions' compliance to this Measure, as part of the 2001 Compliance Enforcement Program.

Please see the summary consideration.

Comments Submitted During Development of Standard on M7

MAIN

There has been much discussion on this Measurement during 2001 – mostly about "WHAT TO DO WITH IT?" If this Measurement is to evolve into something of value, it will need a more NERC wide approach to lay down some minimum guidelines (as somewhat suggested by the III.C guides). If Measurements such as these are to provide consistency in North America, a NERC level group, maybe IDWG, should establish some minimums based on their investigations in 2001 across the regions. Such foundation work will be necessary to incorporate the related concepts into an Organization Standard. If this work does not move ahead, this Measurement should be officially cancelled.

The proposed Standard requires the Regional Reliability Organization to define specifically what it considers to be 'temporary excursions'. If you believe that the definition of 'temporary excursions' needs to be defined and agreed upon on a wider basis that the RRO, please submit this as a comment when the proposed Standards are posted for comment.

MAAC

MAAC believes that these requirements are very important to understanding how the interconnected bulk power system will function during abnormal conditions. In fact MAAC believes that the requirements stated in this single measurement should be broken out into separate measurements. Exemption criteria should be part of any documentation required of the Region.

Agree. Please see the summary consideration.

SERC

Any regional requirements established must consider existing minimum voltage limitations at nuclear switchyards due to NRC degraded grid requirements.

Please see the summary consideration. As proposed, each Regional Reliability Organization must specify requirements and exclusions.

IDWG

The measurement is subject to varying interpretations, and therefore lacks sufficient clarity to render an objective determination of compliance. More information on this particular standard and measure is provided in the attached report.

Please see the summary consideration.

IIIC M8 – Generator controls coordination with unit's short-term capabilities & relays

Summary Consideration:
IIICM8 (Coordination of Generator Controls with the Generator's Short-Term Capabilities and Protective Relays) was translated into new Standard, PRC-019-1 (Coordination of Generator Controls with Generator Capabilities).

The proposed Standard was modified slightly – to change the reporting time from 30 business days to 30 calendar days to improve consistency between standards.

Many Stakeholders indicated that the scope of the 'coordination' required should be specified – several Stakeholders cited work underway by IEEE. The Drafting Team did try to locate the results of the IEEE work, but did not find this on the IEEE Standards web site.

Some Stakeholders expressed concern that some older or smaller units may not be able to produce the required documentation. As proposed, the Generator Owner does not need to provide documentation if its unit has been exempted by its Regional Reliability Organization.

V0 Comments on M8:
Bob Millard MAIN

> This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard. Not well defined and/or detailed.

Most Stakeholders indicated this should move forward as a Standard.

MAPP Planning Standards Subcommittee

> This data is collected under the submittal of dynamics information in Standard 058, therefore the Version 0 NERC Drafting Team should consider combining this Requirement of Standard 065 to Standard 058. While the coordination function mentioned here is important, this measurement should be eliminated to reduce redundant reporting.

The Drafting Team considered merging this Measure with other Standards, but felt that this Standard may need additional technical work, and merging it with other Standards would slow the approval process.

SAR Comments on M8
Christopher Schaeffer; Duke Energy

> --CES-- Concerns were identified with what devices need to be included in a coordination study.
> IEEE is developing a guide on this.
> Should the standard require all or part of the IEEE guide?

Please see the summary consideration.

Doug Hils; Cinergy (Lance Hall; Cinergy Generator)

> Isn't this already covered in II.B.S1.M4?

Agree. There was some duplication in some of the language in IIBS1M4 and IIICM8. IIBM4 included the statement, "Upon request, they (Generator Owners/Operators) shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator's short-term capabilities and protective relays." The Measures and levels of Non-compliance for IIBM4 only addressed the results of testing – the Measures and Levels of Non-Compliance did not address coordination with the generator's short term capabilities and protective relays. In the set of proposed Standards, the coordination aspect is only addressed in the PRC-018.

Tom Mielnik; MidAmerican Energy

> Five business days is not a realistic lead time.
>
> Revisions need to be made based upon comments generated by field testing the standard.

The proposed Standard requires the Generator Owner to produce information on request – within 30 calendar days.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Peter Burke; ATC

Information on older and smaller units may not be readily available or difficult to obtain.

Please see the summary consideration.

Karl A Bryan; US Army Corps of Engineers - Generators

Inner and outer loop controls on the water to wire equipment are not presently modelled, good luck on figuring a way to get information cranked into the powerflow simulation programs.

Please see the summary consideration.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Generation Owners/Operators may not be equipped to determine this information

Please see the summary consideration.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

The reporting is not going to be an issue but the issue will be the methods used to obtain the test data as mentioned in the other standard requiring the testing of equipment.

The proposed Standard does not specify what technique must be used to verify that coordination exists.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Some concerns have been identified with what devices need to be included in the coordination study. While in most cases, following manufacturer's setting recommendations assures proper coordination and protection, development of formal coordination studies for the large number of existing generators will take a significant amount of time and resources.

Please see the summary consideration.

Brandon Snyder; Duke Energy

This will require adequate numbers of skilled and trained engineers to review generation realy settings meet required criteria.

Concerns were identified with what devices need to be included in a coordination study.

IEEE is developing a guide on this. Should the standard require all or part of the IEEE guide?

Addressing personnel issues is outside the scope of this set of SARs.

Please see the summary consideration.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Concerns exist with what devices need to be included in this coordination study. IEEE is developing a guide on this. NERC should work with IEEE to develop guides or standards for this prior to making this a requirement.

Please see the summary consideration.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Comments Submitted During Development of Standard on M8

MAIN

Similar to III.C.M7, some North American guidelines are needed. Depending on the pureness of the reader, the necessary information, such as settings and limits, is limited only by how much the reader wants to do. Again, some group like the IDWG could be helpful here.

Please see the summary consideration.

MAAC

This data is collected under the submittal of dynamics information in II.A.M3. While the coordination function mentioned here is important, we believe that this measurement should be eliminated to reduce redundant reporting. The coordination concept should be made a guideline.

The V0 translation of IIAM3 (Reliability Standard MOD-012) requires the Generator Owner to provide equipment characteristics and system data but doesn't require the Generator Owner to ensure 'coordination'.

Stakeholders may decide that this proposed Standard be made a guideline.

SERC

While there is merit in requiring generators to review and optimize their settings, to do so on all generators in the NERC scope represents a tremendous effort in terms of time and resources. The number of personnel who have the experience and expertise to perform such specialized studies are limited. In addition, validation that each actual setpoint matches the desired setpoint for proper coordination will require thorough testing and calibration of exciter/regulator equipment and protective relays. This will place a huge demand on field personnel who have such experience and expertise and are also limited in number. Most of the testing and calibration must be done during unit outages, which are typically scheduled over a period of years to optimize economic and system impacts.

Thus, it is impractical and unnecessary to expect all plants to be in compliance with this requirement immediately. The standard/measurement should be modified such that generator owners/operators are allowed a reasonable period of time to come into compliance.

Furthermore, no up to date industry or Regional guidance is available on what studies are to be done and how to do these studies. NERC should work with IEEE to develop guides or standards for this prior to making this a requirement.

Please see the summary consideration.

A Regional Reliability Organization may exempt generators from compliance with the requirements in this Standard.

As suggested, the implementation plan for this Standard will need to consider the time it will take for Generator Owners to come into compliance.

IIIC M9 – Information on speed/load governing system

Summary Consideration:
IIICM9 (Speed/Load Governing System) was merged with IIBM5 (Test Results of Speed/Load Governor Controls) into a new Standard, MOD-027-1 (Verification and Status of Generator Frequency Response).

During the field testing of these Planning Measures, objections were raised concerning the sole reliance upon generator testing for many of these Measures. Many Stakeholders indicated that testing isn't the only valid method of verifying accuracy of models and data and suggested revisions that emphasis 'verification' (the desired result) rather than 'testing' (a method for reaching the desired result). The Drafting Team translated these measures so they preserve the intent of verifying accuracy of models and data without requiring generator testing. This should make the set of proposed Standards more acceptable to the Stakeholders.

As many Stakeholders indicated, there are technical issues with speed governor models that need to be resolved. The proposed draft Standard simply requires the Generator Owners to provide information on non-functioning or blocked speed/load governor controls, or controls that influence speed/load governor controls. The requirement to document the characteristics of the generator's speed/load governing system and the requirement to coordinate boiler or nuclear reactor were both dropped from the proposed Standard.

V0 Comments on M9

Bob Millard MAIN

> This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard. Not well defined and/or detailed.

Most Stakeholders indicated this should move forward as a Standard.

MAPP Planning Standards Subcommittee

> Compliance with the design requirements of this measurement as currently written could impact nuclear plant operating licenses and therefore requires additional evaluation that should be addressed within the industry. This measurement should be reviewed and revised as appropriate to ensure that NERC concerns are addressed, but the measurements be consistent with NRC regulations and nuclear safety.
>
> There should be an exception added to cover older generating units with mechanical governors. Manufacturer specifications with regards to governor droop response percentages and dead band are almost non-existent for the older units.

Please see the summary consideration.

Ed Davis Entergy

> Section 9 Requirements – should they be required to include graphs

As proposed, IIICM9 was merged with IIBM5 into a new Standard, MOD-027-1. The proposed Standard requires information be provided on non-functioning or blocked speed/load governor controls, or controls that influence speed/load governor controls. It isn't clear that graphs are needed.

FRCC

> How does this relate to the five-year test schedule of Standard 59? Is this new information?

Version 0 Draft 1's proposed Standard 59 was an even translation of IIBM3 and did require the Generator Owner to verify the gross and net reactive power capability of its units at least every five years. This Standard was removed from Version 0 and the Measure has been modified and translated into MOD-025-1. The proposed MOD-025-1 requires the Generator Owner to 'verify' its gross and net reactive power capability of its units 'in accordance with Regional Reliability Organization requirements.' These changes should make the verification more acceptable to Generator Owners while still meeting the needs of the associated Regional Reliability Organization. The 'verification' addressed under MOD-025-1 is used to ensure that reactive capability does exist and to maintain models. The requirement in proposed MOD-027-1 requires the Generator Owner to provide information on non-functioning or blocked speed/load governor controls, or controls that influence speed/load governor controls. These two Standards are not addressing the same topics.

MAPP Planning Standards Subcommittee

Item (b) would read better as "That confirms the proper coordination of boiler or nuclear reactor control..".

Level 1 of Non-compliance should be referring to Requirement R9-1 and not R1, as this may look like a reference to R1-1 or something other than what was intended.

Agree.

SAR Comments on M9

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Revisions need to be made based upon comments generated by field testing the standard.

Agree. The reporting time was changed from 'five business days' to '30 calendar days'.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Peter Burke; ATC

Information on older and smaller units may not be readily available or difficult to obtain.

The Drafting Team recognizes this and suggests the necessary information may be obtained based on operating MW data – the unit response to frequency transients.

Doug Hils; Cinergy and Lance Hall; Cinergy (Generators)

The requirement for coordination of boiler controls was a confusing issue during audits that included this standard.

Please see the summary consideration.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

The reporting is not going to be an issue but the issue will be the methods used to obtain the test data as mentioned in the other standard requiring the testing of equipment.

Please see the summary consideration.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This must take into account extensive comments received in Phase III field testing.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

A SERC Regional white paper has been developed to address concerns with the standard: The Standard does not recognize there are other control systems in many generation plants that will override free governor response and impact generator MW response to frequency transients. The new modeling method developed by the WECC and included in the SERC IIB supplement appears to address the concerns.

Please see the summary consideration.

Raj Rana; AEP

Measurability may be difficult

Please see the summary consideration.

Brandon Snyder; Duke Energy

Compare to II.B.M5. Challenges; can it be combined with II.B? Address the issue of if a control area can manage the response of units for an overall response or does every unit have to participate (which is implied, but may not be practical). M9-1b requires some tuning of the control system, which most people will not understand how to do nor want to undertake (don't fix it if it aint broke). Gen Owners don't have the technical expertise to address this question, therefore will push back. a) should be in II.B, b) is the tough one and c) is easy The SERC GS has developed a white paper on concerns with the standard, which does not recognize that there are other control systems in many generation plants that will override free governor response and impact generator MW response to frequency transients. The new modelling method developed by the WECC and included in the SERC IIB supplement appears to address the GS concerns.

Please see the summary consideration.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

Compare to II.B.M5. (Test results of speed/load governor controls) Can M.9-1(a) portion of this standard be combined with II.B? Does this address the issue of whether a control area can manage the response of units for an overall response or does every unit have to participate (which is implied, but may not be practical).

III.C.M9-1 (b) requires some tuning of the control system, which most people will not understand how to do nor want to undertake (don't fix it if it aint broke). Generator Owners don't have the technical expertise to address this question, therefore will push back.

M9-1(a) should be in II.B, M9-1 (b) is the tough one, and M9-1 (c) is easy.

The SERC Generation Subcommittee has developed a white paper on concerns with the standard, which does not recognize that there are other control systems in many generation plants that will override free governor response and impact generator MW response to frequency transients.

Please see the summary consideration.

Christopher Schaeffer; Duke Energy

The SERC GS has developed a white paper on concerns with the standard, which does not recognize that there are other control systems in many generation plants that will override free governor response and impact generator MW response to frequency transients. The new modeling method developed by the WECC and included in the SERC IIB supplement appears to address the GS concerns. This standard, along with the IIBM5 requirement should instead, require the Generator Owner/Operator and the Transmission Provider to work together as necessary to assure the frequency response characteristics of significant generating units are understood and modeled appropriately.

Please see the summary consideration.

Comments Submitted During Development of Standard on M9

MAIN

There should be an exception added to cover older generating units with mechanical governors. This template has had the largest number of non-compliance which points to the reality that such units cannot comply similar to newer units. Manufacturer specifications with regards to governor droop response percentages and dead band are almost non-existent for the older units. Generator entities are working with their generator unit manufacturers to secure this data

Please see the summary consideration.

MAAC

This data is collected under the submittal of dynamics information in II.A.M3 and the collection of this data here should be eliminated. The blocked-governor section is important and should remain. Reporting in MAAC will be handled through eDart.

Please see the summary consideration.

SERC

Recommend that this measurement allow for regional generation exemption criteria.

Due to serious concerns expressed by SERC committees and SERC member systems, it is recommended that the implementation of this measurement be delayed and referred to the NERC PSS for additional evaluation. The SERC Generation Working group (GWG) "White Paper to document concerns with Planning Standard III.C.S6.M9" provides a summary of concerns and recommendations for developing appropriate standards and guidelines (copy attached).

Please see the summary consideration.

SERC MEMBERS

Member A : Policy 1 of the NERC Operations Manual lists generation unit governor setting information under “guides”, which historically have not been considered “requirements”. Thus, these are new “requirements” under the Planning Standards. It should also be noted that Policy 1, Section C, Guide 1 states “…should be equipped with governors operational for frequency response unless restricted by regulatory mandates’. This “guidance” did not get translated over into the Planning Standard Requirements.

There are also additional technical concerns with implementation of the recommended “deadband” and “droop” settings, which underscores the complexity of this issue.

Due to the technical complexity of this requirement [and] the potential regulatory impact, it is recommended that this requirement be moved into Phase IV of the Planning Standard Rollout.

Please see the summary consideration.

Member B : Compliance with the design requirements of this measurement as currently written could impact nuclear plant operating licenses and therefore require additional evaluation that should be addressed within the industry. This measurement should be reviewed and revised as appropriate to ensure that NERC concerns are addressed, but are consistent with NRC regulations and nuclear safety.

Please see the summary consideration.

Member E : Compliance with the design requirements of this measurement as currently written could impact nuclear plant operating licenses and therefore requires additional evaluation that should be addressed within the industry. This measurement should be reviewed and revised as appropriate to ensure that NERC concerns are addressed, but the measurements be consistent with NRC regulations and nuclear safety.

Please see the summary consideration.

Member F : It appears that the criteria expressed by NERC in Measurement III.C.S5.M9 do not take into account the many different turbine-generator/reactor control system designs, the inherent limitations of different types of generating units and the relevant regulatory restrictions (such as licensed reactor power limits by the Nuclear Regulatory Commission) placed on the operation of generating units. It is recommended that NERC Planning Standard Measurement III.C.S5.M9 be referred to the NERC [PSS] for additional evaluation.

Please see the summary consideration.

Member G : Member G believes that in its present form, the requirements of this Measure are not sufficiently clear. In addition, Member G believes that the U.S. Nuclear Regulatory Commission licensing requirements for nuclear facilities prohibit compliance with the operating requirements of this Measure.

Please see the summary consideration.

Member H : Compliance with the design requirements of this measurement as currently written could impact nuclear plant operating licenses and therefore require additional evaluation that should be addressed within the industry. This measurement should be reviewed and revised as appropriate to ensure that NERC concerns are addressed, but are consistent with NRC regulations and nuclear safety.

Please see the summary consideration.

SERC White Paper on IIICM9

From: The SERC GWG
To: The SERC CRSC
Subject: White Paper to document concerns with Planning Standards III.C.S5.M9.

The SERC GWG has the following concerns and comments on the III.C.M9 requirement:

From a modeling perspective:

- It's not clear that the models currently used for frequency control are adequate to provide a reasonable indication of the stability of the grid even if this requirement were implemented as written. Reference 1, 2. Some examples of this include:
  - Many generation plants are equipped with plant control systems. These controls will override the response that would be provided by the assumed free governor control. These overriding controls are not currently modeled. This was recognized as early as 1992 (reference 2) and it's unclear if the system modeling community have recognized and acted to address this issue.
  - New digital controllers are provided with a maximum power increase limit, which will limit the amount of response a free governor can provide. The standards dynamic governor models do not account for this and the III.C.M9 Planning Standard requirement does not specify a standardized setting for this control.
  - Mechanical and analog electronic controllers do not allow for the controlled setting of deadband.
  - Testing of generators to obtain governor droop and dead band characteristics is not considered to be practical and the benefits obtained do not justify the costs nor risks to the equipment. Performing a load rejection test at 10-20% of rated output will provide a single data point from an operating point that does not match normal conditions or turbine valve positions.

- The GWG recommends that a national task force be established to study this issue and help develop appropriate standards and guidelines for determining generating plant frequency response characteristics, resulting models, and data verification methodologies for use in simulation studies. It is essential that this task force be staffed with the proper expertise. This should consist of experienced personnel from the following areas:
  - System Planning
  - Systems Operations
  - Generating Plant Design, Operations, Maintenance (Fossil, Hydro, Nuclear)
  - Turbine-Generator Manufacturers
  - Governor Systems Manufacturers
  - Boiler Control Manufacturers
  - Nuclear Reactor Control System Manufacturers

- The task force should address the various types of governor controllers, write specific setting guidelines for each type of controller and develop more realistic models of each type. This effort will need to consider any unique requirements of the plant heat sources and plant control systems.

From a Nuclear plant perspective:

- If the Guide (III.C.G6) settings were implemented as written, this would allow for increases in reactor power above rated if grid frequency transients occur. The amount of increase is not defined. Any increase above 100% reactor power results in potential nuclear regulatory concerns. There may be an avenue for the development of an allowance for limited increases in power due to these transients, however the industry need to work toward a consensus on this. A Nuclear governor task force should be established, possibly including representatives from the NRC, NEI, INPO, and EPRI/NMAC to develop this consensus.

References:

1. 6 April 2001 Letter from John Undril of GE to Chris Schaeffer of Duke Energy "Governing in relation to system frequency response" see attachment 1.
2. EPRI Project RP2473-53 report titled " "Study of Effects of Changes in Speed Governor response on the Security of the North American interconnection".

Please see the summary consideration.

To: Chris Schaeffer, Duke Energy Services
From: John Undrill, GE
Date: 6 April 2001
Re: Governing in relation to system frequency response

1. BACKGROUND

This continues our discussion related to turbine governing and the NERC ' 'Policy 1 - Generation Control and Performance'.

This NERC document is intended to be the standard by which the US interconnected grid is controlled so that power flows between Control Areas are properly regulated. It's main content is description of the technical standards to be met in the control of Area Net Interchange. This description is a codification of the operating practice that has served the US grids well since the invention of area net interchange control over 50 years ago. This practice has been based on the concept that a segment of the grid (originally a single company and lately a grouping of commercial entities) can control the net flow of real power across its enclosing boundary by controlling the collective output of its generators closely to provide exactly the sum of the present load within the boundary plus the power to be exported plus losses. The required close control has been implemented by centralized computers of varying vintage. These centralized computers have issued control signals to power plants using evolving computer and data transmission technologies. The control signals have been received and acted on in power plants of widely varying type with evolving plant control technologies.

Part C of the standard describes standards that member entities of the US grid should meet in responding to changes of grid frequency. This section is based on the implicit recognition of the basic physics of the interconnection, namely that the rotating masses of the turbine-generators must be controlled individually in such a way that the total power production increases as the grid frequency falls. This physical necessity is described in the mathematics and theory of power systems in terms of idealized speed governors of turbines. The basic theory assumes that each individual turbine has a governor that will increase its power in accordance with a pre-set "droop" as its speed decreases.

Part C (7.1) of the NERC policy requires that

"Turbine governors shall be allowed to freely respond to INTERCONNECTION frequency deviation whenever synchronized to the INTERCONNECTION, unless there is a temporary operating problem."

2. REALITIES OF POWER PLANTS

The NERC requirement is certainly the right overriding objective for the grid. It is simply a statement of the obligation of good citizenship among the members of the overall interconnection.

It is equally certain, however, that this requirement is at odds with the reality of operating power plants. It does not recognize that many power plants are based on technology that does not allow the variation of turbine power to be the 'leading' control objective of the plant. Some of the realities in this regard are as follows:

Hydro plants of simple configuration can change their output at will, quite rapidly, and without risk of damaging equipment. The materials in the plant are at low temperatures and are not subject to internal fatiguing stresses when output is changed. Rapid maneuvering causes no accumulation of fatigue or other damage. Constraints on maneuvering are external to the power plant equipment - such as river flow regulations.

Even complex hydro plants cannot maneuver quickly - usually due to civil engineering concerns related to water levels and pressures in tunnels.

Essentially all thermal plants, from small diesels to nuclear plants are operated with metal temperatures such that rapid changes in temperature will produce internal stresses at the level that can cause fatigue damage. The controls of such plants therefore, with increasing emphasis as physical size increases, must take on a primary objective on limiting temperature and rate of change of temperature.

The objective of temperature control has its most prominent role in large gas turbines where temperatures are raised to metallurgical limits in order to maximize efficiency and emission behavior.

In large steam plants, both fired and nuclear, the control of the entire plant is dominated by the need to control pressure and temperature of the steam in the main pressure vessels and piping. The entire technology of large boilers is based on the presumption of relatively slow changes of steam demand. In nuclear boilers the control of steam production is absolutely linked to the control of the nuclear process. These plants are therefore based in their fundamental technology on the principle that the turbine can operate at whatever power output corresponds to the steam production of the boiler.

The result of these realities is that while it is possible to regulate the power output of essentially all generating plants to meet a specified "droop" relationship between grid frequency and power, it is very often impossible for this to be the primary control objective of the plant's turbine. In many thermal plants the control of power is done at a rate consistent with the time scales of the thermal stress, steam management, and nuclear management processes. These plants all have speed governors, as all large rotating masses must have, but these governors are used only for startup and emergency shutdowns.

The spectrum of options in the relationship of turbine speed control to plant control is wide and varied. In the majority of thermal plants, however, this relationship is a characteristic of the basic technology and design. In some cases it is possible for plant operating staff to choose to give the turbine speed governor primary command of the plant in favorable circumstances. In many cases this is impossible because of fundamental design, process stability, process safety, and regulation issues in the steam or nuclear processes.

Overall, therefore, it is unrealistic and impractical to expect that all turbines in a large interconnected grid will be operated under "free governor" control.

The objective is proper and those plants that can do it should operate under free governor control. That there are real costs associated with this should be recognized and dealt with in the commerce of the grid. More importantly at the technical level, the operation of the grid should recognize that the dynamic behavior of much of the plant will not be what is predicted by the simple theory of "free governor" control.

3. RECOGNITION OF THE REALITIES

The consequence of the realities noted above is that understanding of the technical operation of the transmission grid must go far beyond the simple analysis that appears from the basic theory of speed governing. There was certainly great difficulty in doing this in a way that could give useful quantitative information during the early appearance of the interconnected grid, but this understanding is readily available, in computed form, today. There are still limitations on the accuracy of the quantitative information that can be obtained, however.

Please see the summary consideration.

IIIC M10 – Procedure for trip operations of generator protection equipment

Summary Consideration:

IIICM10 (Regional Procedure on Generator Protection Operations) was merged into the already approved Standard, PRC-003-1 (Regional Procedure for Transmission and Generation Protection System Misoperations).

There are four significant changes between the source Measure and the associated requirements in the proposed Standard:

- Stakeholders indicated that conducting an analysis of all 'operations' would be the required analyses should be limited to 'misoperations' rather than 'all operations' and this was changed so the proposed Standard is limited to 'misoperations'.
- Because some misoperations may be so insignificant that they may not need to be analyzed, the source language, 'all misoperations' was modified to 'all applicable misoperations'. Each Regional Reliability Organization may specify which misoperations are covered by its procedure for analyzing and reporting misoperations.
- Stakeholders indicated that providing documentation within 5 business days was too short a time period, and this was changed so the proposed Standard requires each Regional Reliability Organization to provide documentation on request (within 30 calendar days).
- Rather than require documentation of an 'action plan' for a misoperation, the proposed Standard requires documentation of a 'mitigation plan' for a misoperation. The Drafting Team has proposed the following definition of 'mitigation plan:'

  A list of corrective actions and an associated timetable for implementation to remedy a specific problem

The proposed Standard, (PRC-003-1 – Regional Procedure for Transmission and Generation Protection System Misoperations) has a corresponding Standard, PRC-004-1 (Analysis and Reporting of Transmission and Generation Protection System Misoperations) with requirements for the Generator Operator to follow the Regional procedure specified in PRC-003-1). Conforming changes were made to PRC-004-1 to ensure that these two Standards work cooperatively.

Collectively, these changes should make the proposed Standard more acceptable to Stakeholders.

V0 Comments on M10

MAPP Planning Standards Subcommittee

The Requirement should be revised to only require documentation and analysis of misoperations. "operations" seems like it should be replaced with "misoperations" since there doesn't seem to be much meaning in analyzing a proper operation?

Agree.

Level 1 of Non-compliance should be referring to Requirement R9-1 and not R1, as this may look like a reference to R1-1 or something other than what was intended.

The cross references were corrected and updated.

The Levels of Non-compliance should use the word "Regional Reliability Council" versus the word "Regional" in order to fit into the NERC functional model.

The term, 'Regional Reliability Organization' was used throughout the proposed set of Standards.

SAR Comments on M10

Christopher Schaeffer; Duke Energy

- Note that this is in Protection Section below as well. Many generation entities have processes in place to analyze and correct misoperations of protective relaying and believes this requirement is unnecessary. If kept in the SAR, it should allow for the use of existing problem investigation databases and not require additional documentation.

The requirement is essential for reliability and most Stakeholders seemed to support a similar Standard for Transmission Protection.

This does not require any additional documentation if the existing problem investigation database already collects the information needed by the Regional Reliability Organizations.

Karl A Bryan; US Army Corps of Engineers - Generators

Staffing experts capable of performing the analysis that can pass a peer review.

Addressing personnel requirements is beyond the scope of this Standard.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

Implementation of procedure (lack of expertise).

Addressing personnel requirements is beyond the scope of this Standard.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard. Five business days is not reasonable.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Please see the summary consideration.

Brandon Snyder; Duke Energy

Generation has processes in place to analyze and correct misoperations of protective relaying and believes this requirement is unnecessary. If kept in the SAR, it should allow for the use of existing problem investigation databases and not require additional documentation.

The requirement is essential for reliability and most stakeholders seemed to support a similar Standard for Transmission Protection.

This does not require any additional documentation if the existing problem investigation database already collects the information needed by the Regional Reliability Organizations.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

Suggest this requirement be addressed at the Regional Level. If not, we suggest removing from this SAR and placing in the Modeling SAR. Also, the Standard should allow for the use of existing problem investigation databases and not require additional documentation.

The location of a Standard in a particular sequence will not matter when the Standards are entered and retrieved from the relational database planned for NERC's Standards. The Standards have been 'regrouped' based on the consensus of comments received.

Agree. This does not require any additional documentation if the existing problem investigation database already collects the information needed by the Regional Reliability Organizations.

This Standard should be field tested before being adopted.

Please be specific when you recommend field testing to let us know why you think field testing is necessary. While Planning Standards were all field tested, the new Reliability Standards Process does not require that all standards be field tested. Field testing is handled on a case-by-case basis. Not all standards need to be field tested. The Drafting Team will provide its reasoning for its recommendation regarding Field Testing – and will submit this to the Director-Compliance for his consideration in making a recommendation to the SAC. The SAC determines whether Field Testing is needed. (Reference the Reliability Standards Process Manual)

Raj Rana; AEP

This only requires a regional procedure document

Agree: The Standard is a requirement for a Regional procedure.

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed. Without significant rewrite, the III.C measurements will not easily reach consensus.

Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

Suggest this requirement be addressed at Regional level.

This is needed for reliability and most stakeholders seemed to support a similar Standard for Transmission Protection.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Revisions need to be made based upon comments generated by field testing the standard.

Agree. Please see the summary consideration.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Karl A Bryan; US Army Corps of Engineers - Generators

This will most likely be more of a bookkeeping excersize than an in depth analysis of misoperations. One of the benefits that could be realized by this endeavor would be sharing common modes of failure for certain protective devices, the impediment to this sharing of data would be the equipment vendors.

Each owner benefits by conducting an analysis that answers its own questions about any of its generator protection misoperations.

Sharing the results of misoperations is more of an activity related to technical work groups.

Kathleen Goodman; ISO-NE (John Horakh; MAAC) (ISO/RTO Council (9)) (Michael Calimano; NYISO) (Peter Henderson; IESO)

Needs to be clear that the focus is to find and correct misoperations. NOTE; INSERT III.C.S6.M11 AFTER THIS MEASUREMENT

Agree. Please see the summary consideration.

Comments Submitted During Development of Standard on M10

MAAC

Remove the parenthetical statement "(Each Region shall define misoperations.)". It is redundant with the list later in the measurement. Also remove a portion of the parenthetical statement in subsection 2. "…(periodically and…". Since this measurement will only become active when a misoperation takes place, no periodicity needs to be mentioned.

The proposed Standard does not include multiple references to defining misoperations.
The proposed Standard allows each Regional Reliability Organization to establish its own periodicity.

IDWG

PSS may wish to consider combining this measurement with transmission protection and SPS measurements regarding misoperations. Also, based on CRS review of IDWG compliance recommendations, PSS may want to modify these measurements to specify whether regional review of all misoperations is required, or whether intent of the standard is to ensure that the region has a process to ensure that either the region or the owners of the protective devices review misoperations of devices having a regional impact. IDWG's understanding is that CRS may offer additional feedback to PSS concerning this measurement.

Please see the summary consideration.

IIIC M11 – Documentation of all operations of generator protection equipment

Summary Consideration:

IIICM11 (Analysis of Misoperations of Generator Protection Equipment) was merged into the already approved Standard, PRC-004-1 (Analysis and Reporting of Transmission and Generation Protection System Misoperations).

There are three significant changes between the source Measure and the associated requirements in the proposed Standard:

- Stakeholders indicated that applicability should be limited to Generator Owners, rather than both Generator Owners and Generator Operators and this change is reflected in the proposed Standard.
- Because some misoperations may be so insignificant that they may not need to be analyzed, the source language, 'all misoperations' was modified to 'all applicable misoperations'. Each Regional Reliability Organization may specify which misoperations are covered by its procedure for analyzing and reporting misoperations.
- Rather than require documentation of an action plan, the proposed Standard requires documentation of a 'mitigation plan'. The Drafting Team has proposed the following definition of 'mitigation plan:'

  A list of corrective actions and an associated timetable for implementation to remedy a specific problem.

The proposed Standard, (PRC-004-1 – Analysis and Reporting of Transmission and Generation Protection System Misoperations) has a corresponding Standard, PRC-003-1 (Regional Procedure for Transmission and Generation Protection System Misoperations) with requirements for the Regional Reliability Organization to develop a set of procedures for Transmission Operators and Generator Operators to follow in analyzing and reporting on misoperations of protective equipment.

Conforming changes were made to PRC-003-1 to ensure that these two Standards work cooperatively.

Collectively, these changes should make the proposed Standard more acceptable to Stakeholders.

V0 Comments on M11

Bob Millard MAIN

This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard. Not well defined and/or detailed.

Most stakeholders seemed to support the development of this Standard.

MAPP Planning Standards Subcommittee

The Applicability of Section 11 includes "Generator Owner" while the Requirements under Section 11 refer to "Generator Operators". This inconsistency should be fixed.

Agree. Please see the summary consideration.

Ed Davis Entergy

Section 11: Please make Applicability and Requirement R11-1 apply to the same entity, either the Generation Owner or the Generation Operator.

Agree. Please see the summary consideration.

MAPP Planning Standards Subcommittee

The Requirement should be revised to only require documentation and analysis of misoperations. "operations" seems like it should be replaced with "misoperations" since there doesn't seem to be much meaning in analyzing a proper operation?

Agree. Please see the summary consideration.

R11-1 (a) includes a reference to an old NERC template. This reference should be replaced with a relevant reference within the Version 0 posting.

Agree. The proposed Standard reflects the adoption of this suggestion.

The phrase "of all misoperations" should be added after "corrective actions" to clarify what documentation is needed by the Generator Operators.

Agree. Please see the summary consideration.

M11-1 contains a reference to standard 069 instead of 065 of which this Measure is a part of.

Fixed.

M11-2 contains a reference to standard 069 instead of 065 of which this Measure is a part of.

Fixed.

Comments Submitted During Development of Standard on M11

WECC

The requirements and levels of non-compliance for M11 should be modified to require individual entities to analyze all misoperations but requirements for documentation of the analysis and corrective actions should be limited to those misoperations that could have a significant impact on the reliability and operation of the interconnected system. Wording should be added to M11 so that it reads:

> “Generator owners/operators shall analyze all protection system operations and report and maintain a record of all misoperations that could have a significant impact on the reliability and operation of the interconnected system, in accordance with Regional procedures in Measurement III.C.S6.M10. Corrective actions shall be taken to avoid future misoperations.”

Similar wording should be added to the levels of non-compliance to clearly identify that documentation is only required for misoperations that could have had a significant impact on the reliability and operation of the interconnected system.

This type of comment has been submitted in the past by WSCC for measurements requiring documentation for <u>all</u> misoperations of other types of relays.

The associated Standard (for the Regional Reliability Organization’s System Protection Misoperation Reporting Requirements) contains the following which gives each Regional Reliability Organization the flexibility to establish its own reporting thresholds:

> Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affects the reliability of the Bulk Electric Systems as specified by the Regional Reliability Organization.

SERC

The measurement should be revised to only require documentation of misoperations. Documentation of the analysis of all operations should not be required. The second paragraph of the measurement should be revised to:

Documentation of the analysis of misoperations and corrective actions shall be provided to the affected Regions and NERC on request (30 business days).

Agree. Please see the summary consideration.

Nuclear plants have formal Problem Investigation processes with defined time guidelines and manage their resources accordingly. In some cases, this process may allow for more than 30 days to complete investigations into causes of trips. The NERC requirement should not impose unnecessary time requirements more restrictive than existing processes.

The proposed Standard requires providing a report 30 days after a ‘request’ – not 30 days after an ‘event.’

IIIC M12 – Maintenance / testing Program of generation protection systems

Summary Consideration:

IIICM12 (Maintenance and Testing of Generator Protection Systems) was merged into the already approved Standard, PRC-005-1 (Transmission and Generation Protection System Maintenance and Testing).

There are several changes between the source Measure and the associated requirements in the proposed Standard:

- The applicability was changed from the Generator Owner and Generator Operator to just the Generator Owner. As Stakeholders commented, under the Functional Model, the Generator Owner is responsible for having a maintenance program.
- The source Measure required the responsible entity to provide documentation upon request – 'within 30 business days' – and this was changed to 'within 30 calendar days' for greater consistency with other Standards.
- The list of requirements for the maintenance and testing program was expanded so that it exactly matches the list of requirements in the already approved Standard that addresses maintenance and testing programs for transmission protection.
- The requirement to provide documentation to both the Region and NERC was modified to only require that documentation be provided to the Region. NERC is not the Compliance Monitor. If NERC has a reliability-related need to review the documentation, NERC can get the documentation from the Region.
- Comments received following filed testing indicated that the Levels of non-compliance were confusing, and these were modified to replace, ". . . implementation of the maintenance and testing program . . ." with the phrase, ". . . implementation of the documented portions of the maintenance and testing program. . ."

V0 Comments on M12

Dave Angell - WECC Relay WG

The language for protection system maintenance and testing programs should be consistant from standard to standard. The requirement in this standard should match Standard 063, Requirement R3-1. This will provide a consitent reporting requirement for all protection system.

Agree. The generation and transmission requirements were merged into a single Standard and use the same language.

FRCC

Specific test requirements should be included in this standard that enumerates protection systems to be testes such as; Exciter ground detection system, Vibration probes, Thermocouples. In addition, guidelines to determine if non-conventional generating units that may have plant protection systems that aren't turbine or generator protection systems are included in this standard.

Regional Reliability Organizations have the flexibility to add specificity to their Regional requirements.

MAPP Planning Standards Subcommittee

M12-2 seems to have forgotten to mention "who" the generator protection system maintenance and testing program and its implementation needs to be provided to. It was stated within R12-2.

Fixed.

Peter Mackin – TANC

As written, Section 12 is applicable to Generator Operator. This section should be applicable to the Generator Owner instead. This section deals with having a generator protection system maintenance and testing program in place. Equipment maintenance is the responsibility of the Generator Owner and not the Generator Operator. In the Functional Model, one of the tasks for Generator Ownership is:

"Maintain its generation facilities according to prudent utility practices" (Page 38, Functional Model, Version 2)

While one of the tasks for Generator Operation is:
"Develop annual maintenance plan for generating units and performs the day-to-day generator maintenance" (Page 36, Functional Model, Version 2)
this task seems to pertain to the operations of the generator, for example, scheduling when to take the generating unit out of service for maintenance, and not developing a plan for performing maintaining and testing of the specific pieces of equipment such as relay protection systems.

Agree. Please see the summary consideration.

SAR Comments on M12

Ed Davis; Entergy Services

The III.C Measurements met stiff opposition in the SERC Region when they were first introduced during Phase III of the Compliance Program. Many felt that the requirements, themselves, were fundamentally flawed.

Without significant rewrite, the III.C measurements will not easily reach consensus.

Agree. Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Brandon Snyder; Duke Energy

Protection system testing and protection system maintenance need to be clearly defined and differentiated in Reliability Standard 065- R12- 1. I would take testing to be functional testing and maintenance to be individual relay testing, calibration & maintenance. Define scope of generator protection system to include protective relays, instrument transformers and batteries.

Agree. The generation and transmission requirements were merged into a single Standard and use the same language. Regional requirements establish the scope of what must be addressed in the maintenance and testing program.

Southern Co – Gen (3 Gen – 6 Brokers/Aggregators/Marketers)

This standard needs to better define the criteria for determining which generation equipment protection systems are to be included within the standard scope. Also, it needs to better define or differentiate between the terms testing and maintenance, which can mean the same thing or different things.

This may be defined either within the Regional requirements or, if not included in the Regional Requirements, each owner may include its own definition in its program.

Karl A Bryan; US Army Corps of Engineers - Generators

To what level are you going to test to? Also, I would recommend that the maintenance personnel be required to meet a minimum level of competency in order to work on protective relaying.

Addressing personnel requirements is beyond the scope of this Standard.

Ray Morella; FirstEnergy (Kenneth John Dresner; FirstEnergy Solutions)

It seems like some of these standards are already included in ECAR's compliance program such as IIICS7M12. Will the new standard absorb or overlay similar existing standards.

The new Standards are being developed to support reliability throughout NERC and may be duplicated by some Regional Standards.

Comments Submitted During Development of Standard on M12

WECC

The levels of non-compliance are hard to comprehend. Level 2 indicates documentation of the maintenance and testing program is incomplete, but records indicate implementation was on schedule. Level 3 indicates documentation of the maintenance and testing program is incomplete, and records indicate implementation was not on schedule. If documentation is incomplete, it may not be possible to determine if implementation is on schedule or not? WSCC also believes that it is a greater risk to reliability to be behind in implementation of a maintenance plan than it is to have incomplete documentation of a plan. The levels of non-compliance for this measurement should be modified as follows:

Level 1 – Documentation of the maintenance and testing program is incomplete.
Level 2 – Documentation of the maintenance and testing program is complete, but indicates that implementation is not on schedule.
Level 3 – N/A
Level 4 – Leave as is

Please see the summary consideration. The levels of non-compliance were modified to include the phrase, ". . . implementation of the documented portions of the maintenance and testing program. . ."

III E - UVLS

Summary Consideration:
There are three Measures in this series, IIIEM1, IIIEM2 and IIIEM5.

- IIIEM1 (Undervoltage load shedding program documentation) was translated into a new Standard, PRC-021-1 (Under-Voltage Load Shedding Program Data).
- IIIEM2 (Undervoltage load shedding program database) was translated into a new Standard, PRC-020-1 (Under-Voltage Load Shedding Program Database).
- IIIEM5 (Analysis and documentation of UVLS program performance) was translated into a new Standard, PRC-022-1 (Under-Voltage Load Shedding Program Performance).

These Measures were inconsistent – the data that was needed for the database in IIIEM2 did not match the list of data entities were required to provide in IIIEM1. The proposed set of Standards eliminate these discrepancies so that the proposed set of Standards coordinate with one another.

V0 Comments on Multiple Measures

FRCC

At the present time there are very few Regional under-voltage load shedding programs. It appears that until these programs are deemed necessary or the reliability of the Interconnected Systems this standard should not be adopted.

Most Stakeholders supported the inclusion of these Measures in the set of Phase III & IV Measures to be translated into new Standards. There will most likely be more UVLS programs installed based on recommendations in the “US – Canada Power System Outage Task Force’s Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations”.

Frank McElvain - Tri-State G&T

Change wording around in Purpose to read “Provide System preservation measures by implementing an Undervoltage Load Shedding program requiring end users of electricity on the bulk electric system to drop load in an attempt to prevent system voltage collapse or voltage instability.”

In the general Standard Applicability area, Sections 1, 3, and 4 should read “The Responsible Entity may be any and/or all of the following: Load-serving Entity, Transmission Owner, Transmission Operator and Distribution Provider that owns or operates an under voltage load shedding system.” Have this be the wording for the Applicability part of those Sections. Replace the explanation of who a section applies to with The Responsible Entity in the Requirements and Measures parts of these Sections.

The new Standards each have their own Purpose statement.

The responsible entity was replaced with more specific language as suggested.

Ed Davis Entergy

Purpose should refer to system reliability rather than preservation, or preservation of system reliability.

These have the same meaning as the words in the proposed Standards.

Consumers

The purpose of a UVLS program is to prevent a voltage collapse or voltage instability on the transmission system. Therefore, this standard should not be applicable to Load Serving Entities and Distribution Providers.

PRC-021-1 (IIIEM1) is applicable to entities that own or operate UVLS programs – and this could include LSEs.
PRC-020-1 (IIIEM2) is applicable Regional Reliability Organizations
PRC-022-1 (IIIEM5) is applicable to Transmission Owners, Transmission Operators, LSEs and Distribution Providers that own or operate a UVLS.

III E M1 – Documentation of UVLS program

Summary Consideration:

IIIEM1 (Undervoltage load shedding program documentation) was translated into a new Standard, PRC-021-1 (Under-Voltage Load Shedding Program Data).

There are several changes between the source Measure and the associated requirements in the proposed Standard:

- Generic terminology regarding applicability was replaced with the list of specific 'Functions' that need to comply with the Requirements.
- The list of data that must be supplied was modified as follows:
  - size and location of customer ~~demand (~~load~~) blocks (% of connected load),~~ to be interrupted
  - corresponding voltage set points,
  - relay and breaker operating times,
  - ~~intentional delays,~~ time delay from initiation to trip signal
  - related generation protection,
  - islanding schemes,
  - automatic load restoration schemes,
  - or any other schemes that are part of or impact the UVLS programs

The time period for providing requested data was changed from '5 business days' to '30 calendar days'.

V0 Comments on M1:

Frank McElvain - Tri-State G&T

1. Change to read, "automatic load resotoration (see Standard RS 071)".
2. Should read "…and NERC within five business days of a request." to be consistent.
3. Should read "…evidence it provided the documentation in the form of a return mail receipt from NERC in accordance with R1-2." The actual form of the evidence needs to be determined. This comment proposes a mail receipt as a place holder.

1. The source Measure did use this term, and it has been used in the proposed Standard.
2. Please see the summary consideration. The time period for providing the documentation was changed to 30 calendar days.
3. The phrase, 'shall have evidence' is intended to give entities as much flexibility as possible in verifying that they are compliant. If the Drafting Team included language that was more specific, such as requiring that the evidence by a return mail receipt, then an entity that uses e-mail for distribution would need to change its existing process and this would require additional resources without any additional improvement to reliability.

NIPSCO

The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

The phrase, 'shall have evidence' is intended to give entities as much flexibility as possible in verifying that they are compliant. If the Drafting Team included language that was more specific, such as requiring that the evidence by a return mail receipt, then an entity that uses e-mail for distribution would need to change its existing process and this would require additional resources without any additional improvement to reliability.

MAPP Planning Standards Subcommittee

The Transmission Operator reference is not translated accurately. Section 1: Applicability - Trans. Operator missing

The Transmission Operator is included in the proposed Standard.

SAR Comments on M1:

Kathleen Goodman; NE-ISO (Michael Calimano; NYISO) (Peter Henderson; IESO)

Documentation of such program would be easy but this should be applicable where such schemes already exists.

Agree. The proposed Standard indicates that the requirements are applicable to entities that own or operate a UVLS program.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

M1 asks for information from owners/operators of UVLS programs. M2 is a database of this information that is submitted to NERC. The information asked for in each of these Measurements is inconsistent. The data collected for M1 should at least include all the items required in M2 (e.g. type of equipment).

Agree. Please see the summary consideration.

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of UVLS

Agree. Please see the summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

The data collected as a part of this measure should at least include all of the items required in III.E.S1.M2.

Agree. Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Agree. Please see the summary consideration.

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Ray Morella; FirstEnergy

How do these UVLS standards differ from the existing standards for UVLS installations? Coordination among TX and generation companies and NERC regions may be difficult.

V0 included two Standards that address UVLS programs:

- PRC-010-0 requires the owners and operators of UVLS programs conduct periodic assessments of the effectiveness of those UVLS programs.
- PRC-011-0 requires that each UVLS program owner have a UVLS equipment maintenance and testing program in place.

The Measures being addressed through these Phase III & IV SARs do not address the same topics.

- IIIEM1 requires UVLS owners and operators to provide the Regional Reliability Organization with data needed for the Regional UVLS Database
- IIIEM2 requires the Regional Reliability Organization to specify what UVLS data it needs to support its Regional UVLS Database
- IIIEM5 requires UVLS owners and operators to analyze operations and misoperations of UVLS equipment.

Comments Submitted During Development of Standard on M1

SERC

> M1 asks for information from owners/operators of UVLS programs. M2 is a database of this information that is submitted to NERC. The information asked for in each of these Measurements is inconsistent. The data collected for M1 should at least include all the items required in M2 (e.g. type of equipment).

Please see the summary consideration. These Measures were modified so the data requested and the data to be provided match.

IIIE M2 –UVLS Regional Database

Summary Consideration:
IIIEM2 (Undervoltage load shedding program database) was translated into a new Standard, PRC-020-1 (Under-Voltage Load Shedding Program Database).

There are several changes between the source Measure and the associated requirements in the proposed Standard:

- The list of data that must be supplied was modified as follows:
  - ~~Type of UVLS equipment,~~
  - Size and location of customer load to be interrupted
  - Corresponding Voltage set point(s),
  - Time delay from initiation to trip signal.
  - ~~Amount of demand interrupted at peak or other specified level.~~
  - Breaker operating time(s).
  - Related generation protection.
  - Islanding scheme(s).
  - Automatic load restoration scheme(s).
  - Any other schemes that are part of or impact the UVLS programs.

The time period for providing requested data was changed from 30 'business' days' to 30 'calendar' days.

V0 Comments on M2

Bob Millard MAIN

This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

Most Stakeholders seemed to support the development of this Standard.

Consumers

The purpose of a UVLS program is to prevent a voltage collapse or voltage instability on the transmission system. Therefore, this standard should not be applicable to Load Serving Entities and Distribution Providers.

This Standard requires the Regional Reliability Organization to establish what data it needs for its UVLS Database. The proposed Standard is only applicable to the Regional Reliability Organization.

MAPP Planning Standards Subcommittee

Not sure if all Regional Reliability Councils are able to produce a database of UVLS programs immediately. There should be a transition period to allow creation of a database if this standard is kept in Version 0.

Agree. Suggestions for timeframe needed to develop such a database will be helpful to the Drafting Team in developing a proposed Implementation Plan.

Frank McElvain - Tri-State G&T

This requirement is redundant, and should be changed to read, "Each Regional Reliability Council shall provide its current database to NERC within five (or ten) business days of a request." The second measure should delete "to NERC".

The Drafting Team is not sure how the requirement is redundant. NERC is the Compliance Monitor for the Regional Reliability Organization, so the database does need to be provided to NERC upon request – within 30 days.

SAR Comments on M2

Kathleen Goodman; NE-ISO (Michael Calimano; NYISO) (Peter Henderson; IESO)

Documentation of such program would be easy but this should be applicable where such schemes already exists.

Agree.

SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

M1 asks for information from owners/operators of UVLS programs. M2 is a database of this information that is submitted to NERC. The information asked for in each of these Measurements is inconsistent. The data collected for M1 should at least include all the items required in M2 (e.g. type of equipment).

Agree. Please see summary consideration.

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

See comment for III.E.S1-S2.M1 above.

Please see the consideration of comments for IIIES1-S2M1.

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of UVLS

Agree.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft standards.

Raj Rana; AEP

May have difficulty defining the parameters of the database

The proposed Standards identify a specific list of data that should be provided.

Karl A Bryan; US Army Corps of Engineers - Generators

Be sure you build in the maintenance of the large database that this requirement will result in.

Adding a requirement to maintain the database is outside the scope of this set of SARs – but could be addressed with the submission of another SAR.

Ray Morella; FirstEnergy

How do these UVLS standards differ from the existing standards for UVLS installations?

V0 included two Standards that address UVLS programs:

- PRC-010-0 requires the owners and operators of UVLS programs conduct periodic assessments of the effectiveness of those UVLS programs.
- PRC-011-0 requires that each UVLS program owner have a UVLS equipment maintenance and testing program in place.

The Measures being addressed through these Phase III & IV SARs do not address the same topics.

- IIIEM1 requires UVLS owners and operators to provide the Regional Reliability Organization with data needed for the Regional UVLS Database
- IIIEM2 requires the Regional Reliability Organization to specify what UVLS data it needs to support its Regional UVLS Database
- IIIEM5 requires UVLS owners and operators to analyze operations and misoperations of UVLS equipment.

IIIE M5 – Analysis & documentation of UVLS event

Summary Consideration:

IIIEM5 (Analysis and documentation of UVLS program performance) was translated into a new Standard, PRC-022-1 (Under-Voltage Load Shedding Program Performance).

There are several changes between the source Measure and the associated requirements in the proposed Standard:

- Generic terminology regarding applicability was replaced with the list of specific 'Functions' that need to comply with the Requirements.
- Added, 'A description of the event including the initiating conditions' to the list of elements that must be included in the analysis of UVLS operations, misoperations and failures to operate
- A description of the event including initiating conditions.
- Changed the time period for providing documentation from 30 'business' days to 30 'calendar' days

V0 Comments on M5

Bob Millard – MAIN

This section should not move forward in Version 0 since it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

Most Stakeholders seemed to support the development of this Standard.

Frank McElvain - Tri-State G&T

1. In the general Standard Applicability area, Sections 1, 3, and 4 should read "The Responsible Entity may be any and/or all of the following: Load-serving Entity, Transmission Owner, Transmission Operator and Distribution Provider that owns or operates an under voltage load shedding system." Have this be the wording for the Applicability part of those Sections. Replace the explanation of who a section applies to with The Responsible Entity in the Requirements and Measures parts of these Sections.

2. Should include language to clarify that the analysis is of the actual performance with spelled out items to include in that performance evaluation, such as causes for misoperations or failures to operate and their corrective actions, the date of implementation of those actions, etc.

3. Replace "of undervoltage load shedding operations, misoperations, and failures to operate" with "as specified in R5-1" to be consistent.

4. Delete "undervoltage load shedding operations, misoperations, and failures to operate" to be consistent.

5. Should read "…and NERC within 30 business days of a request." to be consistent. Also reduce 30 business days to 5 or 10.

6. Change to read, "…and failures to operate conforms to the requirements specified in 069-R5-1".

1. The Applicability was changed as suggested, to clarify that this is only applicable to entities that own or operate a UVLS system
2. The elements that must be included in the analysis are identified as 'subrequirements' in the proposed Standard.

3. The proposed Standard's Measures use a 'cross reference' as suggested to indicate that the responsible entity must have, " . . . documentation to show its analysis of UVLS operations, misoperations and failures to operate, as specified in Reliability Standard PRC-022-1_R1."
4. Deleting the phrase as suggested would make the Measure more difficult to interpret.
5. The language in the proposed Standard specifies that the documentation must be provided to the Regional Reliability Organization within 30 calendar days of a request. This is consistent with other Standards.
6. This seems to be the same suggestion as #3 and this was changed as suggested.

MAPP Planning Standards Subcommittee

The Transmission Operator reference is not translated accurately. Section 5, add Transmission Operator in R5-1, R5-2

The proposed Standard clearly states that the Transmission Operator is responsible for PRC-022-1_R1 and R2 if that Transmission Operator operates a UVLS.

NIPSCO

The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

The phrase, 'shall have evidence' is intended to give entities as much flexibility as possible in verifying that they are compliant. If the Drafting Team included language that was more specific, such as requiring that the evidence by a Fed Ex receipt, then an entity that use e-mail to distribute its reporting requirements would need to change its existing process and begin using Fed Ex, and this would require additional resources without any additional improvement to reliability.

SAR Comments on M5

Christopher Schaeffer; Duke Energy

Protection system testing and protection system maintenance need to be clearly defined and differentiated in Reliability Standard 065- R12- 1. I would take testing to be functional testing and maintenance to be individual relay testing, calibration & maintenance. Define scope of generator protection system to include protective relays, instrument transformers and batteries.

The proposed Standard does not include any maintenance or testing requirements. The proposed Standard requires entities that do own or operate a UVLS to document its analysis of UVLS operations, misoperations and failures to operate.

Kathleen Goodman; NE-ISO (Michael Calimano; NYISO)

Requirements for UVLS should only be triggered on an Area's identified need for such a program.

As proposed, the Standard indicates the Requirements must be met by those entities that own or operate a UVLS. The proposed Standard does not include any requirements to install a UVLS.

Peter Henderson; IESO

Documentation of such program would be easy but this should be applicable where such schemes already exists.

As proposed, the Standard indicates the Requirements must be met by those entities that own or operate a UVLS. The proposed Standard does not include any requirements to install a UVLS.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of UVLS

As proposed, the Standard indicates the Requirements must be met by those entities that own or operate a UVLS. The proposed Standard does not include any requirements to install a UVLS.

Ray Morella; FirstEnergy

How do these UVLS standards differ from the existing standards for UVLS installations?

V0 included two Standards that address UVLS programs:

- PRC-010-0 requires the owners and operators of UVLS programs conduct periodic assessments of the effectiveness of those UVLS programs.
- PRC-011-0 requires that each UVLS program owner have a UVLS equipment maintenance and testing program in place.

The Measures being addressed through these Phase III & IV SARs do not address the same topics.

- IIIEM1 requires UVLS owners and operators to provide the Regional Reliability Organization with data needed for the Regional UVLS Database
- IIIEM2 requires the Regional Reliability Organization to specify what UVLS data it needs to support its Regional UVLS Database
- IIIEM5 requires UVLS owners and operators to analyze operations and misoperations of UVLS equipment.

IV A – System Blackstart Capability

Summary Consideration:

There are two Measures in this series – IVAM2 and IVAM3.

IVAM2 (Demonstrate through simulation or testing that a blackstart generating unit can perform its function) was merged with IVAM3 (Diagram the number, size, and location of system blackstart generating units and the initial transmission switching) and incorporated into the already approved V0 Standard EOP-005-1- (System Restoration Plans).

V0 Comments on Multiple Measures:

MAPP Planning Standards Subcommittee

> Throughout Standard 070, it appears that "Restoration Plan", "Reliability Authority's system restoration plan", "regional blackstart capability plan", and "Regional Reliability Council's blackstart capability plan" are used interchangeably. A defined term should be used throughout 070 and applied throughout 070 and 071.

Agree. The Drafting Team for Phase III & IV Standards added a definition for 'Restoration Plan' for review and approval during the development of these Standards. The term, 'Blackstart Capability Plan' was defined during the development of V0 Standards. The Drafting Team is using adjectives to clarify the ownership of Blackstart Capability Plans and Restoration Plans. All references for the new Requirements and associated Measures use the term, 'the Transmission Operator's Restoration Plan'.

Ed Davis Entergy

> Reference to 30 Business Days in at several places in this standard is not appropriate, these should be 30 (calendar) days. 30 days and 30 Business day appears to have been used in the original standard with no logical reasons.

Agree. All of the V0 Planning Standards were modified to indicate that the turnaround time for providing documentation would be either 'five business days' or '30 calendar days'. These default time periods have been adopted for use with Version 1 Planning Standards. The response time can be different if there are unique requirements for reporting.

IV A M2 – Demonstrate blackstart unit can perform its function

Summary Consideration:

IVAM2 (Demonstrate through simulation or testing that a blackstart generating unit can perform its function) was merged with IVAM3 (Diagram the number, size, and location of system blackstart generating units and the initial transmission switching) and incorporated into the already approved V0 Standard EOP-005-1- (System Restoration Plans).

V0 Comments on M2

Bob Millard - MAIN

This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 070, Section 1. Also it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

Most Stakeholders indicated this should move forward as a Standard.

MAPP Planning Standards Subcommittee

Requirement R2-1 states in the last sentence that unit testing must be performed at least every five years while item #3 under R1-1 states that one third of blackstart units shall be tested annually.

EOP-005 (IVAM2) refers to periodicity of simulation and testing of the blackstart plan. EOP-009 (IVAM4) refers to periodicity of testing blackstart units. This is not a conflict.

Should Standard 070 be changed to test the blackstart units once every three years to better align with the NERC Operating Standards? Here may be one example of redundancy between operating standards and planning standards.

EOP-005 (IVAM2) refers to periodicity of simulation and testing of the blackstart plan. EOP-009 (IVAM4) refers to periodicity of testing blackstart units. This is not a redundancy.

The Standards have been consolidated into just reliability Standards, with no distinction between planning and operating Standards.

The Standard Language that was dropped in Section 2 does not seem to be fully captured in the requirements. The Standard Language introduces the idea of Regional coordination in developing a blackstart plan. It is only once a regional plan is developed can an analysis be performed to determine if the blackstart plan is sufficient. It is recommended to broaden Applicability to include Regional Reliability Councils for coordination purposes.

Regional Reliability Organizational restoration plans are addressed in approved Version 0 EOP-007. Language was added to clarify that system blackstart generating units must be sufficient to meet Regional Reliability Organization Restoration Plan requirements as specified in Reliability Standard EOP-007_R1.2.

Documentation of the most recent blackstart tests would most likely be obtained by the Regional Reliability Councils with participation by the Transmission Operators therefore broadening section 2 applicability to include Transmission Operators as well as Regional Reliability Councils.

This is a revision to approved Version 0 EOP-009 that needs to be addressed in the future. The Transmission Operator would expected to coordinate or execute the tests and should be in a position to provide the test results.

SAR Comments on M2

Ray Morella; FirstEnergy

This should be easy as long as simualtion data remains acceptable.

The Standard allows simulation.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

William Smith; Allegheny Power

The difficulty in achieving industry consensus will depend how "simulation or testing" clarified. The definition of this phrase can have financial impact.

The Standard allows simulation or testing and is therefore flexible.

Karl A Bryan; US Army Corps of Engineers - Generators

The blackstarting of a facility is not the difficult part, it is actually charging up a dead transmission line and then connecting load to the line that is the proof that we should be striving for.

The Drafting Team added requirements for documenting cranking path capability to EOP-005-1. There may be limitations on testing of actual equipment that can be addressed through simulation.

Alan Adamson; NYSRC

Development of this standard and the next standard should recognize and be coordinated with the Version 0 EOP Standards

Agree. This measure has been integrated into the requirements of V0 EOP-005-1.

Comments Submitted During Development of Standard on M2

WECC

The levels of non-compliance should be modified to include failure to test blackstart units. Suggest modifying levels of non-compliance as follows:

Level 1 – Documentation of annual startup and operation testing of blackstart generating unit(s) is incomplete or indicates units were not tested on an annual basis.
Level 2 – N/A
Level 3 – The blackstart generating unit(s) did not start as required in the Regional restoration plan.
Level 4 – Blackstart generating unit(s) were not tested.

The proposed Standard allows the use of simulation as well as actual testing, so including levels of non-compliance that address whether or not the generator did start would not be appropriate. The proposed Standard does assign Level 4 if the results are either not provided or not compliant with the associated Regional Reliability Organization's requirements.

SERC MEMBER

Member X: Standards P6T2 and IVA.S1.M2 are almost identical except for the three-year versus the five-year time period requirements. One carries a $2000 fine and the other a letter. There appears to be redundancy as well as the possibility of double jeopardy in this instance. This issue should be resolved in this field test environment before these standards complete due process.

Penalties and sanctions will not be included in these Phase III & IV NERC Standards.
EOP-005 (M2) refers to periodicity of simulation and testing of the blackstart plan. EOP-009 (M4) refers to periodicity of testing blackstart units. This is not a conflict.

IV A M3 – Diagram blackstart units & initial switching

Summary Consideration:

IVAM2 (Demonstrate through simulation or testing that a blackstart generating unit can perform its function) was merged with IVAM3 (Diagram the number, size, and location of system blackstart generating units and the initial transmission switching) and incorporated into the already approved V0 Standard EOP-005-1- (System Restoration Plans).

Many Stakeholders expressed security-related concerns with distribution of drawing. The proposed Standard clarifies that drawings must be maintained, but there is no requirement to distribute these drawings. This requirement was expanded to require that the Transmission Operator document the cranking paths or maintain cranking path diagrams associated between each blackstart generating unit and the unit(s) to be cranked.

V0 Comments on M3

Bob Millard – MAIN

This section should not move forward in Version 0 since it is essentially already covered by Version 0 STD 070, Section 1. Also it is more procedure/data oriented, not really stand alone "standard" material but more tools or reference material for executing a standard.

Most Stakeholders indicated this should move forward as a Standard.

Ed Davis Entergy

Section 3 Applicability should include Reliability Authority along with Transmission Operator.

This is addressed in EOP-006-1 and references the Reliability Coordinator. The Transmission Operator requirements are incorporated in EOP-005-1.

SAR Comments on M3

ISO/RTO Council (9) (Peter Henderson; IESO)

Does not address the issue of security of such diagrams. Confidentiality of these diagrams should be maintained.

Please see the summary consideration.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

The Drafting Team has considered all comments, including those from field testing, in developing the draft Standards.

Raj Rana; AEP

Question value of simply requiring a map of the location of the BS units

Agree. Please see the summary consideration.

Brandon Snyder; Duke Energy (SERC EC Planning (6 Trans Owners – 1 RTO/ISO/RRC)

These diagrams are considered Critical Energy Infrasture Information. The measurement needs to recognize the confidential nature of this data.

Please see the summary consideration.

Kathleen Goodman; ISO-NE

Confidentiality of these diagrams should be maintained. Is this really a requirement that NERC should have or the Areas or Regions?

How will this help maintain reliability and what are the risks associated with having such documentation?

Please see the summary consideration.

The proposed Standard allows the responsible entity to determine how detailed these diagrams should be. Knowing in advance which paths are the most effective for restoration could be of great assistance during an actual restoration.

Michael Calimano; NYISO

Need to address the issue of security of such diagrams. Confidentiality of these diagrams should be maintained.

Please see the summary consideration.

Ray Morella; FirstEnergy

A good idea to have a coordinated effort with neighboring Control Areas involved to provide input and have an accurate diagram including knowledge of neighboring Control Areas cabablities.

The Standards do require coordination of blackstart plans (see EOP-005 requirement 4).

Southern Co – Trans, Ops, Plng & EMS (11 Trans Own – 1 LSE)

This will be difficult without addressing potential security concerns around submitting this confidential data to NERC.

Please see the summary consideration.

Comments Submitted During Development of Standard on M3

SERC MEMBER

Member F : NERC needs to clarify whether SERC need copies of diagrams or if it is sufficient for them to be available at the member's site. Are the appropriate diagrams one line diagrams or maps?

Please see the summary consideration.

The proposed Standard requires the Transmission Operator to maintain documentation, not to distribute it.

IV B – ALR

Summary Consideration:

There are four Measures in this series:

- IVBM1 (Documentation of Regional Automatic Load Restoration Policies and Programs)
- IVBM2 (Documentation of Automatic Load Restoration Programs)
- IVBM3 (Assessment of the Effectiveness of Automatic Load Restoration Programs)
- IVBM4 (Automatic Load Restoration Equipment Maintenance Requirements)

The Drafting Team recommends that this series of Measures addressing Automatic Load Restoration (ALR) be removed from the set of Standards being moved forward for approval. The Drafting Team did not attempt to provide responses to individual comments. Stakeholder comments indicated that there are relatively few ALR installations – too few to warrant a NERC Reliability Standard. In particular, the Interconnection Dynamics Working Group submitted the following recommendation for this series of Standards:

> Auto load restoration is not widely used. In the field tests, it turned out that this measurement was only applicable to 3 Regions, and one of the Regions did not think the measurement applied to them because the ALR was local in nature and does not impact the bulk power system. The PSS may wish to consider whether a national standard that applies to only three of ten regions is justified.

Most other comments received indicated this Measure, if developed into a Standard, should only be applicable to those few entities that actually have ALRs installed. Furthermore, since the Drafting Team has identified weaknesses in the Standards for UVLS program (and its implementation paradigm), which need to be addressed to ensure Bulk Electric System (BES) reliability, it is apparent to the Drafting Team that translating the existing ALR Standards has very limited impact on enhancing the BES reliability.

V0 Comments on Multiple Measures:

Bob Millard – MAIN

> This entire standard should not move forward in Version 0 since it is more limited in its uses and does not appear to be needed as a nation wide standard at this time.

IV B M1 – Document ALR programs including database

Summary Consideration:

The Drafting Team recommends that the series of Measures (IVBM1, IVBM2, IVBM3, and IVBM4) be dropped based on Stakeholder comments as well as their limited significance in ensuring BES reliability, given the rather meager number of ALR installations within the industry. The Drafting Team did not attempt to provide responses to individual comments. In particular, the Interconnection Dynamics Working Group submitted the following recommendation for this series of Standards:

> Auto load restoration is not widely used. In the field tests, it turned out that this measurement was only applicable to 3 Regions, and one of the Regions did not think the measurement applied to them because the ALR was local in nature and does not impact the bulk power system. The PSS may wish to consider whether a national Standard that applies to only three of ten Regions is justified.

Most other comments received indicated this Measure, if developed into a Standard, should only be applicable to those few entities that actually have ALRs installed. Furthermore, since the Drafting Team has identified weaknesses in the Standards for UVLS program (and its implementation paradigm), which need to be addressed to ensure Bulk Electric System (BES) reliability, it is apparent to the Drafting Team that translating the existing ALR Standards has very limited impact on enhancing the BES reliability.

V0 Comments on M1:

MAPP Planning Standards Subcommittee

Applicable NERC Standards should be changed to the specific NERC standards.

There is only one measure for multiple standards in each of the sections. To be consistent with other standards in Version 0, there should be one measure for each standard.

NIPSCO

The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

Peter Mackin - TANC

On page 4 of 10, section 1 of levels of noncompliance - We believe the reference (Reliability Standard 071-R1-1 number 4) should be (Reliability Standard 071-R1-1 element d).

SAR Comments on M1:

Kathleen Goodman; ISO-NE (Michael Calimano; NYISO)

Requirements for ALR should only be triggered on an Area's identified need for such a program.

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of ALR

Peter Henderson; IESO

Documentation of such program would be easy but this should be applicable where such schemes already exists.

Raj Rana; AEP

Parameters of data base could be an issue.

Tom Mielnik; MidAmerican Energy

Five business days is not a realistic lead time.

Revisions need to be made based upon comments generated by field testing the standard.

Comments Submitted During Development of Standard on M1

IDWG

Auto load restoration is not widely used. In the field tests, it turned out that this measurement was only applicable to 3 Regions, and one of the Regions did not think the measurement applied to them because the ALR was local in nature and does not impact the bulk power system. The PSS may wish to consider whether a national standard that applies to only three of ten regions is justified.

IV B M2 – Document ALR programs with Regional requirements

Summary Consideration:

The Drafting Team recommends that the series of Measures (IVBM1, IVBM2, IVBM3, and IVBM4) be dropped based on Stakeholder comments as well as their limited significance in ensuring BES reliability, given the rather meager number of ALR installations within the industry. The Drafting Team did not attempt to provide responses to individual comments. In particular, the Interconnection Dynamics Working Group submitted the following recommendation for this series of Standards:

> Auto load restoration is not widely used. In the field tests, it turned out that this measurement was only applicable to 3 Regions, and one of the Regions did not think the measurement applied to them because the ALR was local in nature and does not impact the bulk power system. The PSS may wish to consider whether a national standard that applies to only three of ten Regions is justified.

Most other comments received indicated this Measure, if developed into a Standard, should only be applicable to those few entities that actually have ALRs installed. Furthermore, since the Drafting Team has identified weaknesses in the Standards for UVLS program (and its implementation paradigm), which need to be addressed to ensure Bulk Electric System (BES) reliability, it is apparent to the Drafting Team that translating the existing ALR Standards has very limited impact on enhancing the BES reliability.

V0 Comments on M2

NIPSCO

> The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

SAR Comments on M2

Kathleen Goodman; ISO-NE (Michael Calimano; NYISO)

> Requirements for ALR should only be triggered on an Area's identified need for such a program.

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

> Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of ALR

Peter Henderson; IESO

> Documentation of such program would be easy but this should be applicable where such schemes already exists.

Tom Mielnik; MidAmerican Energy

> Five business days is not a realistic lead time.
>
> Revisions need to be made based upon comments generated by field testing the standard.

IV B M3 – Assess effectiveness of ALR programs

Summary Consideration:

The Drafting Team recommends that the series of Measures (IVBM1, IVBM2, IVBM3, and IVBM4) be dropped based on Stakeholder comments as well as their limited significance in ensuring BES reliability, given the rather meager number of ALR installations within the industry. The Drafting Team did not attempt to provide responses to individual comments. In particular, the Interconnection Dynamics Working Group submitted the following recommendation for this series of Standards:

> Auto load restoration is not widely used. In the field tests, it turned out that this measurement was only applicable to 3 Regions, and one of the Regions did not think the measurement applied to them because the ALR was local in nature and does not impact the bulk power system. The PSS may wish to consider whether a national Standard that applies to only three of ten regions is justified.

Most other comments received indicated this Measure, if developed into a Standard, should only be applicable to those few entities that actually have ALRs installed. Furthermore, since the Drafting Team has identified weaknesses in the Standards for UVLS program (and its implementation paradigm), which need to be addressed to ensure Bulk Electric System (BES) reliability, it is apparent to the Drafting Team that translating the existing ALR Standards has very limited impact on enhancing the BES reliability.

V0 Comments on M3

NIPSCO

> The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

Ed Davis – Entergy

> Section 3 Applicability should also include Reliability Authority under the definition of Responsible Entity.
>
> Section 3 Compliance Monitoring Process does not appear to be complete as it does not provide sufficient details.

SAR Comments on M3

Kathleen Goodman; ISO-NE (Michael Calimano; NYISO)

> Requirements for ALR should only be triggered on an Area's identified need for such a program.

Tom Mielnik; MidAmerican Energy

> Revisions need to be made based upon comments generated by field testing the standard.

John Horakh; MAAC (ISO/RTO Council (9)) (Peter Henderson; IESO)

> Automatic Load Restoration owners/operators may not be equipped to perform this assessment, which should be done on a Regional coordinated basis

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

> Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of ALR

IV B M4 – Document ALR equipment testing / maintenance program

Summary Consideration:

The Drafting Team recommends that the series of Measures (IVBM1, IVBM2, IVBM3, and IVBM4) be dropped based on Stakeholder comments as well as their limited significance in ensuring BES reliability, given the rather meager number of ALR installations within the industry. In particular, the Interconnection Dynamics Working Group submitted the following recommendation for this series of Standards:

Auto load restoration is not widely used. In the field tests, it turned out that this measurement was only applicable to 3 Regions, and one of the Regions did not think the measurement applied to them because the ALR was local in nature and does not impact the bulk power system. The PSS may wish to consider whether a national Standard that applies to only three of ten regions is justified.

Most other comments received indicated this Measure, if developed into a Standard, should only be applicable to those few entities that actually have ALRs installed. Furthermore, since the Drafting Team has identified weaknesses in the Standards for UVLS program (and its implementation paradigm), which need to be addressed to ensure Bulk Electric System (BES) reliability, it is apparent to the DRAFTING TEAM that translating the existing ALR Standards has very limited impact on enhancing the BES reliability.

V0 Comments on M4

NIPSCO

The "shall have evidence" phrase is vague and may be unnecessary considering that the requesting entity should know if its requested information is supplied.

SAR Comments on M4

Kathleen Goodman; ISO-NE (Michael Calimano; NYISO)

Requirements for ALR should only be triggered on an Area's identified need for such a program.

Tom Mielnik; MidAmerican Energy

Revisions need to be made based upon comments generated by field testing the standard.

NPCC-CP9 (6 Trans Owners – 7 RTO/ISO/RRC)

Yes but only where it exists--Documentation of such a program would be considered easy but this should not be considered as an endorsement of the use of ALR