Individual or group. (54 Responses)
Name (33 Responses)
Organization (33 Responses)
Group Name (21 Responses)
Lead Contact (21 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (54 Responses)
Question 1 (48 Responses)
Question 1 Comments (49 Responses)
Question 2 (44 Responses)
Question 2 Comments (49 Responses)

Individual
Michael Moltane
ITC
Agree
MRO NSRF

Individual
Mikhail Y. Borodulin
New York Independent System Operator (NYISO)

1) Table of Compliance Elements (page 13), under “Moderate VSL” It reads: “…but failed to include greater than 25% or less than or equal to 50% of the required components…” Here, the first “or” is mathematically incorrect. Instead, “and” is suggested. A similar correction is needed under “High VSL.” 2) MOD-032-1 – ATTACHMENT 1, Data Reporting Requirements, pp. 19-21 In the column “dynamics”: “If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables. Instead, the following is suggested: “If a user-written model(s) is submitted in place of a generic or library model or otherwise to represent a power system component, the modeling package must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables, algebraic variables and other essential model constants and variables. The package must also include model validation materials.” 3) MOD-032-1 – ATTACHMENT 1, Data Reporting Requirements, p. 19 It is suggested that that in the column “dynamics”, Item 6, “Wind turbine data… ” be replaced with “Wind turbine generator data and data associated with a wind power plant (farm), including relevant wind plant collector system data and central controller data.” 4) MOD-032-1 – ATTACHMENT 1, Data Reporting Requirements, p. 20 It is suggested that in the column “dynamics”, after Item 9, the following be added: “Data associated with other new power system components (including but no limited to energy storage devices, variable frequency transformers, etc.).
Section 6, Background, p. 4 reads: “MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation.” It is suggested that the following

footnote (after the words "…modeling and validation") be added (in the bottom of the page) "It is assumed that for each user-written model of an individual power system component or device represented in the Interconnection-wide dynamics case(s), the modeling package supplied by the model developer includes validation materials justifying the use of the model in power system stability studies."
Group
Northeast Power Coordinating Council
Guy Zito
No
Referring to MOD-032-01 – ATTACHMENT 1: Data Reporting Requirements, to clarify the intent of 3b, suggest revising it to read: b. reactive power capabilities – reactive power capability values corresponding to an adequate number of real power values chosen within the maximum and minimum values in 3a above. Plotting of real/reactive points should result in a reasonably accurate duplication of the generator's continuous capability curve supplied by the manufacturer. Requirement R2 reads: "…For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." This is a measure, and its inclusion in the Requirement, despite the rationale provided in the SDT's Consideration of Comments Summary does not conform to the results-based principle. The sentence itself does not contribute to a reliability outcome. We again ask the SDT to move this sentence into M2 to strengthen the latter part of the Measure. This move does not adversely affect the assessment and demonstration capability when an entity does not submit the required modeling data simply because there have not been any changes. This is an attestation, not a requirement. The wording of Requirement R4 refers to the "creation of the interconnection-wide cases(s)". R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. This should more properly refer to "the compilation of submitted data to form new Interconnection-wide base cases". The work performed by NERC or its designee takes the data submitted by the Planning Coordinators/Transmission Planners and assembles it into new base cases. Suggested rewording for R4: R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support the compilation of submitted data to form new interconnection-wide base cases that includes the Planning Coordinator's planning area. The MOD-032-1 standard places the responsibility for determining data requirements and reporting procedures on the Planning Coordinators and Transmission Planners (Requirement R2). It also places the responsibility for making available models of its planning area for use in the assembly of base cases on the Planning Coordinators (Requirement R4). The standard should require that these be "independent" Planning Coordinators to prevent any submission of equipment or system representation data that can influence base case simulation results. In the second paragraph of the Rationale Box for R4, the "Requirement R3 in support of" should read "Requirement R2 in support of".

No
The MOD-033-1 standard places the responsibility for implementation of a documented data validation process on the Planning Coordinator. For this standard it should also be required that the Planning Coordinators be “independent”.
Individual
Thomas Foltz
American Electric Power
No
Attachment 1: Steady-State Column, Item 2: Given the current definition of LSE and the inconsistent manner in which it is sometimes interpreted, AEP disagrees with specifying the LSE as the sole functional entity required to provide this information. This information is provided by various entities within each interconnection, and as a result, it is often left to the Planning Coordinator or RRO to determine exactly who provides this info. AEP recommends adding flexibility to accommodate the various approaches taken in how this information is collected. The standard is written too prescriptively in regards who provides what data and to whom (for example in Attachment 1, Steady-State Column, item D where it states that the GO would provide the TOP regulated bus and voltage set point data). As stated earlier, we recommend adding flexibility to the standard. In general, AEP supports the overall direction the drafting team is taking on this project, though we strongly recommend the drafting team pursue the recommendations provided above.
Individual
Larisa Loyferman
CenterPoint Energy
No
CenterPoint Energy (CNP) appreciates the efforts of the SDT and agrees with the approach of consolidating existing MOD standards 010 through 015 into one standard. Our specific concers are detailed below: For Requirement R1.1, CenterPoint Energy believes that the Attachment 1 table is still too prescriptive and needs to be modified to retain the high level numbered items for steady-state and short circuit data and to remove the details identified by the lowercase letters. As we pointed out before, this is just unnecessary and will create a compliance burden on the utilities. As an alternative, CenterPoint Energy requests consideration of the following comments/suggestions: 1. CNP suggests to change the parenthetical statement in Attachment 1 under Steady-State to the following: “Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided or no data at all, for different modeling scenarios.” 2. For item 7.b. - regulated voltage band limits, CNP suggests adding an asterisk. For fixed shunts, there is no need for a voltage band. Or as an alternative use the “if applicable” statement for all pieces of data such as 7.b. or 7.d. just like was used for item 8.c. 3. For item 5. - Demand under Dynamics section, where the LSE is listed as the responsible functional entity, it is unclear what is meant by Demand for dynamic purposes. CNP suggests changing “Demand” in the dynamics section to “Demand Classification” and adding a footnote similar to the existing footnote for Aggregate Demand in

the Steady-State section. The footnote can read: “For purposes of this item, Demand classification is the Demand breakdown based on customer type and/or load type classification as a percentage of the Aggregate Demand”.
Yes
Individual
Silvia Parada Mitchell
NextEra Energy/Florida Power and Light
No
The language in R4 is insufficiently precise in allowing for continuation of the interconnection-wide data base assembly procedures. It is recommended R4 be reworded as follows: R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the designated Interconnection-wide Data Base Group and to the ERO on request.
No
The replacement of the term “validation” with “comparison” is a significant improvement in the draft Standard. The level of engineering effort required to perform these types of comparison can be quite large and burdensome depending on the need to exactly match initial conditions. The 24 month cycle for these engineering studies is excessive and overly burdensome without an associated reliability benenfit, and, thus, it is recommended the cycle be change to once every five years.
Individual
Michael Falvo
Michael Falvo
No
We continue to disagree with the second sentence in R2 which says: “For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.” This is a measure, and its inclusion in the requirement despite the rationale provided in the SDT’s Summary Consideration of Commetn does not conform with the Results-based principle since the sentence itself does not contribute to a reliability outcome. We once again ask the SDT to move this part into M2 to strengthen the latter part in the measure. This move does not adversely affect the assessment and demonstration capability when an entity does not submit the required modeling data simply because there has not been any changes. This is an attestation, not a requirement. In the Rationale Box for R4, the “Requirement R3 in support of” should read “Requirement R2 in support of”.
Yes
Group
Transmission Compliance and Modeling
Tait Willis
Agree
Seattle City Light

Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Although Manitoba Hydro is in general agreement with the standard, we have the following comments: a) R2 – the words 'a registered entity shall submit' seem to be missing after the words 'last submission'. b) R3, 3.1 – 'current data' would more appropriately be referred to as 'data already submitted'. c) R3, 3.2 – the words 'of written notification' should follow 'of receipt'. d) M3 – current should be 'data already submitted' and the reference to 'within 90 calendar days of the request' should be 'within 90 calendar days of written notification'. e) R4 – there are no time or frequency requirements specified here. The Measure language refers to having provided \ 'when requested' so at the very least R4 should refer to receiving a request for such models from the ERO or its designee. Preferably some time frame would also be included i.e. within x number of days from the date of receipt of a request… f) Compliance, 1.2 – there are capitalized references to Applicable Entity which are not defined terms. g) Compliance, 1.3 – list the applicable processes here instead of referring to those in the NERC Rules of Procedures. The current language refers specifically to a process found in the NERC Rules of Procedure, which may be an issue because Manitoba Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure.
No
a) Is the Initial Performance of Periodic Requirements (requirement parts 1.1 and 1.2) meant to comply 24 months after effective date of MOD-033-01 (NERC adopted date) even if the Standard is not approved by an applicable government authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect? Or does the 24 months start from the applicable governmental adoption of the standard? b) There are portions of the standard that are too ambiguous and should be clairified to more specific items. Below are some examples: R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation; The model year to be validated is not specified even if the intent is the next year model. For example, could wording such as "Year One " planning model be used where Year One is defined in the NERC Glossary of Terms? 1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and This requirement is too vague – what is unacceptable differences? This could lead to interpretations/disagreements between the NERC auditors and Planning Coordinators. 1.4. Guidelines to resolve differences in performance identified under Part 1.3. Too ambiguous. A more reasonable approach could be to have a requirement to make the PC/TP identify a mitigation plan if there is an unacceptable difference. c) The rationale for R1 is troubling in that there is a discussion about how it is difficult to capture in words in the requirement itself the

details of how to validate modeling data and that these details are left to guidance documents. This is problematic as Manitoba has not and will not necessarily in the future adopted guidance documents as law. If there are specific details or requirements with respect to validating modeling data, it is best that it be included in the body of the requirement itself if the expectation is compliance with such details or requirements. d) R1, 1.4 – 'differences' should be 'unacceptable differences' to be consistent with the rest of the requirement. e) R2 – the words 'who has indicated a need for the data for validation purposes' should follow 'under Requirement R1' to be consistent with the Measure. f) R2 – the words 'from such Planning Coordinator' should follow 'written request'. g) Compliance, 1.2 – there are capitalized references to Applicable Entity which are not defined terms. h) Compliance, 1.3 – list the applicable processes here instead of referring to those in the NERC Rules of Procedures. The current language refers specifically to a process found in the NERC Rules of Procedure, which may be an issue because Manitoba Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
My main concern with the current draft is that the "joint" or "jointly develop" requirments in a mandatory and enforceable standard create and auditing nightmare of demonstrating the joint cooperation. Any requirements should be specific to a registered function and non-duplicative.
Individual
Brett Holland
Kansas City Power & Light
Yes
No
KCP&L is concerned with R1.2 language, which states: 1.2. Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months. If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs; The issue is with the local event occurring past the 24 calendar months. There is no specific timeframe given in which the comparison should be completed after the event. The concern is that an auditor, without clear guidance from the requirement, could expect it to be done more quickly than is possible.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power (GO) continues to be opposed to each PC developing its own data submission requirements, as this will lead to inconsistent, changing requirements. If the PC continues to be

the developer of the data submission requirements, some parameters need to be put around the how long a particular set of of requirements are valid, along with a mechanism for determining which requirements applicable for a particular submission (as will be required for compliance audits). For example, in January a PC determines that the data submission requirements are for generators 157 MVA and above and the data must be submitted in GE PSLF format. So, the GO makes plans to purchase licenses and train personnel in GE PSLF, and plans testing workload based on the 157MVA requirement. Then, 6 months later (possibly due to required collaboration with a new TP), the PC determines that the data must be submitted in some web application format, but must work in PowerWorld, GE PSLF, and Siemens PSS/E. And generators that are part of a facility greater than 174MVA are included. According to the standard, this is an entirely conceivable scenario. The GO is left in a position of trying to maintain compliance with a changing set of requirements. The alternative is more work, but in the end worth it. That is to develop the data submission requirements and procedures in the standards framework, and make it consistent at least across each interconnection. In addition to the practical effects of the PC writing their own procedures, I would think FERC would have difficulty evaluating the standard with such significant "fill in the blank" elements. Idaho Power TP's comments: R1. . . for the Planning Coordinator's planning area . . . could mean the overall interconnection with which all PCs are associated. In this interpretation, WECC would be a planning area; MISO would be another planning area; ERCOT would be another planning area. However, if a planning area is a sub-area of an interconnection, then a different interpretation of R1 is necessary. Since I believe that a planning area is intended here to mean a sub-area of an interconnection, I would then offer the following: R1. Planning Coordinators, each representing the Planning Coordinator's planning area, along with associated Transmission Planners, shall jointly develop steady-state, dynamic, and short circuit modeling data requirements and reporting procedures on an interconnection-wide basis that include: . . . If, in fact, each Planning Coordinator and associated TPs that represent a planning area were to autonomously develop their own data requirements and reporting procedures (as is clearly stated in the MOD-032 team's suggested R1 wording - "for the Planning Coordinator's planning area") without making it a collaborative effort among all PCs/TPs within a common interconnection, then there could be 21 different answers for the western interconnection (WECC). Each answer might work just fine for the given planning area, but R4 says "each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee" with the implication that the ERO or designee will be combining the 21 potentially disparate sets of data into a single coherent interconnection-wide case. This could end up being very confusing at best and disastrous at worst if there is no interconnection-wide collaborative effort to develop a common set of data requirements and reporting procedures. Issues at the ERO or designee could result from planning area differences in the required "data format", the required "level of detail", the "case types and scenarios to be modeled" and the "schedules for data submission". It seems an extraordinary oversight not to require these critical data requirements and reporting procedures to be developed as a collaborative effort among all PCs/TPs within a common interconnection. MOD-011 and MOD-013 recognized this need in R1 of each Standard wherein was stated (quoting from MOD-011): "The Regional Reliability

Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection." Clearly, the concern was for developing comprehensive steady-state data requirements and reporting procedures on an interconnection-wide basis with a coordinator of the joint effort (the RRO in this case) so as to end up with a common set of jointly developed data requirements and reporting procedures that would be usable on an interconnection-wide basis. The requirement calls for joint development of data requirements and reporting procedures. It is not prescriptive as to how this is to be accomplished. Functionally, today's area coordinators jointly develop data requirements and reporting procedures in the joint SRWG forum for the Western interconnection. Since most area coordinators are also PCs and TPs, requirement R1 is really already being met if we change the R1 wording to allow the interconnection-wide development of the data requirements and reporting procedures. R1.2 states that the data reporting procedures each PC develops must maintain consistency with the interconnection-wide case procedures for the items listed in 1.2.1-1.2.4. MOD-032 as drafted does not contain requirements for the establishment and maintenance of interconnection wide processes by the ERO designee. It also does not require the ERO designee to communicate changes to the interconnection wide case building procedure so PC’s can update their R1 process to remain consistent with the interconnection-wide procedure. The ERO designee per the language of the R1 is merely a recipient of "models" to "support the creation of interconnection-wide cases". The ERO designee has no other function called out in MOD-032. The language of R1 does not provide a framework or support requirements for the establishment and maintenance of interconnection-wide processes by the ERO designee. Introduction of the Requirements assigned to a Reliability Assurer NERC functional entity would better accomplish what MOD-11 and MOD-13 intended to accomplish and would also provide a framework in MOD-032 to support establishment and maintenance of an interconnection-wide case developed and data reporting process. M1: Instead of each PC and TP separately providing evidence of each planning areas autonomous efforts, perhaps the measure could require evidence of the posted interconnection-wide data requirements and reporting procedures. After all, the real evidence of the joint effort is the jointly developed document. Maybe something like: M1. The jointly developed data requirements and reporting procedures specified in Requirement R1 (which now includes the coordination function of the RA) shall be distributed or posted (making them available to those responsible for providing data) as evidence that each Planning Coordinator and Transmission Planner has jointly developed the data requirements and reporting procedures specified in Requirement R1. The difficulty with this approach is that there is not a single clearly identifiable entity to take responsibility for the lack of the jointly developed data requirements and reporting procedures if the requirement calls for joint development in an interconnection-wide forum. My proposed language removes individual responsibility from "each Planning Coordinator and each of its Transmission Planners" and requires each to collectively perform the development function on

an interconnection-wide basis. This then suggests the measure of R1 must no longer focus on each planning area PC/TP, but must measure the product of their collaborative efforts done in the interest of the interconnection, the jointly developed data requirements and reporting procedures. Again, MOD-011 and MOD-013 recognized this need in M1 of each Standard wherein was stated (quoting from MOD-011): "The Regional Reliability Organization shall have documentation of its Interconnection’s steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2." Again, the concern was for developing comprehensive, consistent and uniform steady-state data requirements and reporting procedures on an interconnection-wide basis. It is hard to envision how this can be accomplished without a single entity such as the Reliability Assurer (RA) directing and coordinating the effort. Under Guidelines and Technical Basis at the end of MOD-032, the following statement is made: "The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s)." While it may be the intent to not change established processes and procedures in each of the interconnections, the words that have been drafted in MOD-032 do not support that intent. If each planning area is required to autonomously develop data requirements and reporting procedures that ignore the coordinated needs of the (western) interconnection, established processes and procedures could be significantly compromised. The existing WECC data requirement and reporting procedures have all been developed to collectively address the needs of all players in the WECC. We simply could not function if each of the 21 control areas within the WECC case-building framework were required to develop data requirements and reporting procedures just for each Planning Coordinator's planning area without intentional regard for the other 20 areas.
Yes
Idaho Power System Planning agrees with the revisions of MOD-033-1 and has no further comments on MOD-033-1.
Group
Oklahoma Gas and Electric
Terri Pyle
Yes
No
While OG&E agrees with the rationale for MOD-033-1, we still believe that specific requirements for the guidelines need to be spelled out in R1.3 and R1.4 to address concerns from TOP point of view for Requirement 2 due to excess burden that may be imposed on the TOP to provide data to the Planning Coordinator.
Individual
David Jendras
Ameren

No
We believe that Standard MOD-032-1 should also be applicable to Distribution Providers, who would provide data for facilities <100 kV which would be included in the models. Also, the Distribution Provider provides load forecast data for use in model development, as well as short circuit data for transformer connections to the transmission system that serves network subtransmission facilities. We do not believe there is a need for an interconnection-wide short circuit model. Existing short-circuit models contain considerably more detail than a typical powerflow model, therefore this makes reconciling bus numbers and names between short-circuit and powerflow models difficult or impossible. Therefore, while both short-circuit and powerflow models are needed for different aspects of system analysis, the two types of models do not need to be mutually compatible with each other. Therefore, we request that R4 in MOD-032 be limited to powerflow and dynamics models. Other specific comments regarding short-circuit model data: (1) We ask the SDT to clarify why planning horizon cases need negative and zero sequence data? Based on our experience, three phase faults pose the greatest challenge to breaker interrupting capability which is addressed by TPL-001-2 R2.3 & R2.8 and FAC-002-1 R1.1.4 (experience has shown us that phase to ground fault is somewhat higher at many plant switchyards, but the breaker single phase capability generally sufficiently exceeds that slight increase.) We ask the SDT to consider the following: (a) At the very most GSU zero sequence and generating plant outlet line Zo are needed for station grounding purposes or to confirm our first sentence; we recommend case handling this at the time of a connection study or major expansion (e.g. line or generator addition) instead of requiring this detail annually. (b) From our experience Zero sequence mutuals are not needed. Also, for such planning studies negative sequence can be assumed equal to positive sequence. (2) Our understanding is that The Application Guidelines intent is not to change present data collection efforts. In our case, for short circuit models, these are handled via the Regional Entity, not the Planning Coordinator. (3) We request the SDT to clarify what 'all applicable elements' are for short circuit in Attachment 1, or at the very least do so in the Application Guide. (4) We ask the SDT what information or data would be provided by the BA, LSE, or TSP for short circuit modeling purposes (Attachment 1 table, short circuit item #3). If none can be identified, these entities should not be applicable. (5) We believe Resource planners aren’t the appropriate entity to provide future steady-state, dynamics, or short-circuit data (Attachment 1). The Generator Owner should be responsible, once the project is announced, even for the future generator data. This data should be part of the generator interconnection process. (6) We believe that the phrase 'Other information requested by ….' Appearing in Attachment 1 is still too open ended, giving a route for requesting copious amounts of modeling data, for powerflow, dynamics, or short-circuit models, and wasting valuable resource time.
No
We request clarification because it appears to us that, by comparison of the Planning Coordinator’s portion of the existing system in a dynamic model to actual system response, as described in R1.2, using a ‘dynamic local event’, that there may be a contradiction implicit within the requirement. If this requirement is to verify the dynamic response of the ENTIRE Planning Coordinator’s system, and the use of a major system disturbance for this purpose is not intended, then it could take a plethora of smaller dynamic local events spaced across the

Planning Coordinator’s portion of the system to provide sufficient event coverage of a Planning Coordinator’s system for validation purposes.
Individual
Chris Scanlon
Exelon
No
Exelon voted affirmatively in the previous ballot, agreed with the approach the Team was pursuing and provided specific comments. Exelon TO's continue to agree with the majority of the revisions, but the wording in the standard should strongly discourage, if not forbid, the use of user-written models in the system-wide dynamics cases. Simply requiring the block diagrams, values, and names for parameters does not prevent the user written models from being included in the cases. At least one of the RROs has been actively involved in discouraging the use of user-written models; this effort should continue. While there are valid reasons not to include the RROs in the standard as responsible entities, it would be useful for the SDT to better describe how the RROs might fit into the case-building process. Processes have been developed over the past 6 or 7 years that work well, and the changes to the standard risk undoing the progress made since the initial implementation of the MOD standards being replaced.
No
In its current form, the draft MOD-033-1 standard does not apply to transmission owners, but in cases where the transmission owner is not also the transmission planner or transmission operator, the transmission owner may possess data needed to support MOD-033-1. MOD-033-1 does not provide a means for the Planning Coordinator or Transmission Planner to obtain that data. Exelon TO's agree with other comments, on the previous draft, that MOD-032-1 and MOD-033-1 should be voted on separately.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
Within MOD-032-1’s VSL table, there is a logic error causing both R1’s and R4’s “Moderate VSL” as well as “High VSL” conditional statements to always evaluate True. For all occurrences, REPLACE: “or less than or equal to”, WITH: “but less than or equal to”, RATIONALE: Fix logic to be consistent with R2 & R3 conditional statements. If this logic error is not fixed, then AECI will have to vote Negative on the next (Final?) round of ballot.
Yes
Group
ISO/RTO Standards Review Committee
Gregary Campoli
No
Applicability The SRC does not agree with the need to redefine Planning Coordinator as a

combination of Planning Coordinators and Planning Authorities given that version 5 of the Functional Model does not include “Planning Authority” as a functional entity. The SRC requests that the Standard Drafting Team consider the removal of Balancing Authority as an applicable entity. The only reference to BA in Attachment 1 (data reporting requirements for steady state, dynamics, and short circuit) is in the catchall category (for example, item number 9 under steady state - Other Information Requested by the PC or TP necessary for modeling purposes). It appears unlikely that the BA will need to supply modeling data that is not already being provided by any of the other functional entities that the standard applies to. R1 The SRC recognizes that for R1 the SDT revised the previous post and deleted the phrase “in conjunction with each of its Transmissionn Planners” but does not agree with with the addition of “jointly develop(ing)” a Plan. The reason for dropping the former phrase was to eliminate a requirement shared by two Functional Entities. The added phrase does not resolve that dilemma. The SRC proposes either the new phrase be deleted (and recognize that that the PC will incorporate all the TPs it needs for its Plans (the option the SRC supports)); or add a requirement that mandates all TPs develop Plans and another requirement that the PC use those plans (a cleaner approach than the current R1 but one that imposes a specific method on how PCs create their plans. The SRC recommends that the word “jointly” be deleted from R1. (Please note, regarding the issue of "joint", ERCOT & CASIO abstain from supporting that part of the comment.) R2 The SRC does not believe that a BA is responsible for Dynamic Data models. The SRC recommends the BA be dropped from R2. The SRC does not agree with the inclusion of the last sentence in R2 (i.e. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.) and that the sentence be moved into the measures section. This move does not adversely affect the assessment and demonstration capability when an entity does not submit the required modeling data simply because there has not been any changes. This is an attestation, not a requirement. This is a measure, and its inclusion in the requirement despite the rationale provided in the SDT’s Summary Consideration of Commetn does not conform with the Results-based principle since the sentence itself does not contribute to a reliability outcome. The SRC recommends the SDT move this sentence into M2 to strengthen the latter part in the measure. R4 In the Rationale Box for R4, the “Requirement R3 in support of” should read “Requirement R2 in support of”. The SRC strongly supports the statement in Attachment 1 on user-written models “(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)” Also in Attachment 1, add mode of operaration to Steady state Transformer Characteristics as shown: 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* i. mode of operation (fixed, discrete, continuous, etc.) other suggested additions/revisions to Attachment 1 of MOD-32: 2. Aggregate Demand c. Demand type (scaling, non-scaling) 3. Generating Units b. reactive power capabilities –Provide 10 points (5 positive, 5 negative) to define reactive capability curve (“D” curve) with one set of points at maximum real power capability in part 3a and one set of points at minimum power capability

in part 3a, the remaining 3 pairs of points spaced in-between. 4. AC Transmission Line e. Line length in miles f. Line name designation 6. Transformer k. Transformer name designation
Yes
Group
Electric Market Policy, NERC & FERC Compliance
Randi Heise
Yes
Dominion agrees with the Standard Drafting Team that MOD-032-1 supports the proposed retirement of Standards MOD-10-0, MOD-011-0 MOC-013-1, MOD-014-0 and MOD-015-1 and is responsive to theFERC's directives.
No
Dominion does not agree with R2 as it requires an entity to provide data that, in some cases, it is not required to have. We believe that actual system behavior data will often consist of data provided by DME equipment and/or PMUs. PRC-018-1 applies only to Generation Owner and Transmission Owner. R4 of that standard requires these entities to provide information pursuant to PRC-002 Requirement 4. This standard was remanded by FERC and therefore has no standing. We can find no IRO or TOP standard in effect that requires the Generation Owner and Transmission Owner to provide information to the RC or TOP, nor obligates the RC or TOP to perform or support after-the-fact analysis. Dominion therefore suggests that R2 be modified to also include Generation Owner and Transmission Owner. We suggest R2 be revised to read "Each Generator Owner, Reliability Coordinator, Transmission Owner and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
Individual
John Seelke
Public Service Enterprise Group
No
We require clarification on three issues. 1. Clearly define real power capabilities – gross minimum values (Attachment 1, Column 1, 3a, real power capabilities – maximum and minimum values) DESCRIPTION: Gross Minimum Real Power (Here on referred to as Pmin) needs to be clearly defined in MOD-032-01. Pmin can be based on a generating units environmental compliance, stability limit, economic constraints, etc. For it to be useful in planning studies (for reliability purposes and system expansion) what would NERC like the Pmin to be based on? BACKGROUND: Power flow simulation programs (PSS/E, Tara, etc.) can use Pmin as one of the methods to address system reliability. If Pmin for a generator is specified the power flow program can use it to "runback" a generator to its Pmin value to reduce loading on a line under contingency? For example. A 100MW generator (Pmax= 100MW, Pmin = 50MW) is connected to two lines (Each line is rated at 90MVA/15min) and one of the lines is

out of service which results in the other line being overloaded to 100MW (100/90 = 111% of 15min rating). Hence the generator will need to be runback to below 90MW (assume perfect p.f) within 15 minutes (rating of the line) to reduce line loading and maintain system reliability. The generator could be shutdown (it will most likely be a hard shutdown) but to maintain system reliability (not eat into the system reserve) it could be kept ON but at a lower MW output. Hence it is impotant that the minimum output for a generator be tied to some sort of time value which serves to improve system reliability. 2. Clearly define "Normal Plant Configuration" (Attachment 1, Column 1, 3c, station service auxiliary load for normal plant configuration) DESCRIPTION: Station load can vary under different plant configurations. For example a combined cycle plant may consist of 3 Combustion Turbines (CT) and 1 Steam Turbine (ST) i.e. 3x1 however it may have the ability to be run in different configurations 2 x 1 (2CT and 1 ST). What configuration should be used? Also should the load for a plant be provided as the Plant as whole (3 x 1) or on a load Per unit/machine basis (i.e. load for a single CT, etc.) We suggest providing Auxiliary loads under Full output and under generator shutdown to provide an "adequate" range. Also, the location of the where the auxiliary power comes from should be needed. For instance some generating stations can have an auxiliary feeds from a nearby substations (for increased reliability) and in addition to this there are instances when auxiliary power is provided from one or more power sources. 3. Provide Clarity on data required for "In-service status (Attachment 1, Column 1, 3h, in-service status) DESCRIPTION: We are accustomed to provding retirement dates for existing equipment and in-service dates for new equipment. What "in-service status" data could GOs be requested to provide for for different scenarios (i.e. fall, winter, summer)? Depending upon the data requested, there may be data confidentiality concerns.
Yes
Individual
Larry Brusseau
Mid-Continent Area Power Pool
No
I have some compliance concerns on the R1, specifically, "the PC and TP shall jointly develope…" From the RSAW in note to the auditor, "Auditor will seek evidence that the entity jointly developed the requirements and reporting procedures as required." The weight of compliance has to potential to undermine the data requirement development. What is important is the data requirements and data. Attachment 1 concerns: 1. The DC transmission item in the power flow section of Attachment 1 should be more specific in its requirements 2. The dynamics data section of Attachment 1 should be expanded and more detailed to reflect the detail contained in the power flow section of Attachment 1 General Comments: MOD-032-1 & MOD-033-1 do not answer the question on who is responsible for the actual building of the model. Data is to be collected and a model is to be verified, however, who is required to build the model: The ERO, the interconnections, the Regional Entities? Under what requirements are the models to be built? Currently the NERC registry has 80 registered PCs and 185 TPs. NERC and industry need to re-assess the continent-wide model development process. All PCs or TPs should have access to the ERO models regardless of their relationship with the designee.

Suggest a requirement stating that the ERO (or designee) models are available by request to any PC or TP. Currently there is not a process for the ERO to make the models available. ERAG is not the NERC designee and is a separate organization of 6 regions. Modifications to the ERAG charter should it become the designee need to be made so that all NERC registered entities have access to the information.
No
Currenlty the NERC registry has 80 registered PCs and 185 TPs. R1 states that each PC needs to compare the performance of its portion of the system to actual system behavior. With such a high number of PCs, the degree of variables makes for an almost impossible task to identify where discrepancies model validation occur. 24 months is too short of an interval to perform the steady state and dynamic model validation. Suggest an interval of 36 months for for the validation period.
Individual
Kathleen Goodman
ISO New England, Inc.
Agree
IRC SRC
Individual
Oliver Burke
Entergy Services, Inc.
No
1. Please clarify what "all applicable elements" are for short circuit in Attachment 1. At the very least do so in the Application Guide. 2. The treatment of detailed data for older units should be addressed. The use of non-detailed synchronous generator or condenser modeling should be permitted for units with nameplate ratings less than or equal to 50 MVA (small units) for specific circumstances, including: a) detailed data is not available because the manufacturer is non longer in business, detailed data is not available because the unit is older than 1970. This criteria matches that of the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Work Group (MMWG) Procedure Manual, Version 10 (10 July 2013, Section 9.2, p.37). Unconventional data requests that would require reverse/extensive engineering techniques to fulfill should also be addressed. Parts of the data request are duplicative with existing standards and other standards currently under development. The approved VAR-002-2b, R4 already requires he GO to provide the TOP and TP with transformer data listed in Attachment 1, steady-state data, items 6b,6c, and 6d. What information or data would be provided by the BA, LSE, or TSP for short circuit modeling purposes (Attachment 1 table, short circuit item #3)? If none can be identified, these entities should not be applicable.
No
It would appear that, with comparison of a Planning Coordinator's portion of the existing system in a dynamic model to actual system response, as described in R1.2, using a 'dynamic local event', there may be a contradiction implicit within the requirement. If the requirement is to verify the dynamic response of the ENTIRE Planning Coordinator's system, and the use of a

major system disturbance for this purpose is not intended, then it could take a plethora of smaller dynamic local events spaced across the Planning Coordinator's portion of the system to provide sufficient event coverage of a Planning Coordinator's system for validation purposes.
Individual
Richard Vine
California ISO
Yes
The California ISO suggests the following specific edits and additions to the MOD-032-1 Attachment 1 steady-state data requirements sections 4, 6 and 8: 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. meter position if applicable e. in-service status* 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. mode of operation/tap ratios (fixed, voltage, real power flow, phase shifting, or phase angle or other)* d. minimum and maximum tap ratio or phase angle limits e. number of tap positions (for both the ULTC and NLTC), tap ratio (for ULTC and NLTC transformers) or phase angle for phase-shifting transformer f. regulated bus and scheduled voltage (for voltage regulating transformers)* g. voltage or MW regulating bands h. ratings (normal and emergency)* i. in-service status* 8. Static Var Systems, FACTS or dynamic VAR systems [TO] a. reactive limits b. regulated bus and voltage set point* c. mode of operation (fixed, discrete, continuous, fixed/switched shunt, if applicable d. in-service status* The California ISO also suggests the following specific edits and additions to MOD-032-1 Attachment 1, dynamics data requirement 8: 8. Static Var Systems, FACTS or dynamic VAR systems [GO, TO, LSE] Additionally, the California ISO has the following general comments related to the Attachment 1 Data Reporting Requirements: 1. Attachment 1 Steady state data (pages 19-20) includes shunt capacitors and reactors, but doesn't include series compensation and series reactors. The AC line parameter list also doesn't list series capacitors or series reactors. The ISO feels that both sections should include these important items. Additionally, the ISO feels Attachment 1 should include synchronous condensers which are very important to ISO planning and operation. 2. Attachment 1 in the list of the required dynamic models doesn't include any relays (pages 19-20). This seems like an oversight. 3. For dynamic data, the way the standard currently reads it seems that there are no restrictions on user-written models. The ISO recommends that user-written models can be submitted only if a generic or library model is not available for that technology. In all other cases, generic or library models should be used.
Yes
Individual
Steve Hill
Northern California Power Agency
No
I agree with all the directives except one. I believe it would help small entities (especially to Generator Owners and Operators) to make a small change to R2. Many small entities do not have a Planning Coordinator. This a problem especially in the WECC. Is it possible to change the

wording for R2 to say "… short circuit modeling data to its Transmission Planner(s) and/or Planning Coordinator(s)or Area Coordinator (s) according to the data requirements and reporting procedures developed by its …) The same change would need to be made for the Violation Severity Levels for R2. This is a small and subtle change, but of upmost importance to small entities who have no Planning Coordinator. WECC is well aware of this problem, but to date there is no solution. I think it might help WECC if they could work with the Area Coordinators to have them be Planning Coordinators for some of the small entities. There may be contractual modifications necessary, but the Area Coordinator is doing many of the tasks already that a Planning Coordinator would do.
Yes
Group
Tennessee Valley Authority
Brandy Spraker
No
We agree with a subset of the comments below submitted by the Planning Standards Subcommittee. Standard MOD-032-1 should also be applicable to Distribution Providers, who would provide data for facilities <100 kV which would be included in the models. Also, the Distribution Provider provides load forecast data for use in model development, as well as short circuit data for transformer connections to the transmission system that serves network subtransmission facilities. With respect to short circuit data – there is no need for an interconnection-wide short circuit model. Further, existing short-circuit models contain considerably more detail than a typical powerflow model, making reconciling bus numbers and names between short-circuit and powerflow models difficult or impossible. Therefore, while both short-circuit and powerflow models are needed for different aspects of system analysis, the two types of models do not need to be mutually compatible with each other. Therefore, R4 in MOD-032 should be limited to powerflow and dynamics models. Other specific comments regarding short-circuit model data: 1) Application Guide says they don't want to change present data collection efforts. In our case, for short circuit models, these are handled via the Regional Entity, not the Planning Coordinator. 2) The treatment of detailed data for older units should be addressed. The use of non-detailed synchronous generator or condenser modeling should be permitted for units with nameplate ratings less than or equal to 50 MVA (small units) for specific circumstances, including: a) detailed data is not available because the manufacturer is no longer in business, detailed data is not available because the unit is older than 1970. This criteria matches that of the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual, Version 10 (10 Jul 2013, Section 9.2, p. 37). Unconventional data requests that would require reverse/extensive engineering techniques to fulfill should also be addressed. Attachment 1, dynamic data items 2, 3, and 4 should be subparts of item 1 as they only apply to synchronous generators. Attachment 1, steady-state data, Item 3d does not belong in the GO, RP category. The regulated bus and voltage setpoint is not provided to the GO by the TOP. VAR-001-2. R4 requires the TOP to provide this information to the GOP, not the GO. We suggest that the TOP be added to MOD-032 to require this information be provided by the TOP directly to the TP. 3)

Resource planners aren't the appropriate entity to provide future steady-state, dynamics, or short-circuit data (Attachment 1). The Generator Owner should be responsible, once the project is announced, even for the future generator data. This data should be part of the generator interconnection process. 4) In addition, we re-submit the concern for consistency among PCs that are independently developing modeling requirements and reporting procedures. See below. "There is insufficient linkage between R1 and R5 for the Eastern Interconnection. Within the Eastern Interconnection, there are fifty (50) registered Planning Authorities (based on 8/27/2013 NERC Compliance Registry Matrix). While the standard is written in a way that will allow established multiregional(ERAG) model development processes for steady-state and dynamics models to continue, it fails to capture the common framework and sequence that must be established at the Eastern Interconnection level for coordinated Interconnection-wide model development to occur. The "ERO or its designee" (currently ERAG for the Eastern Interconnection) should be the organization that establishes modeling data requirements and reporting procedures for the Eastern Interconnection level models. This is implied in R5, but not explicitly addressed in R1. Each PC may develop as many models as it deems necessary for its own area; however the Interconnection-wide models should be a minimum set of models that all of the PCs in the Eastern Interconnection develop under a common set of guidelines and assumptions that are established by the "ERO or its designee", in conjunction with PCs within the Interconnection. A key word used in the purpose of the standard is "consistent". It is unreasonable to assume that fifty diverse PCs will independently develop modeling requirements and reporting procedures that will roll up into a consistent end product without some form of collective governance. The drafting team should consider developing a separate standard for each Interconnection (reference IRO-006 as precedent) in recognition of the current modeling practices employed in each Interconnection. While a "one size fits all" standard is understandably desired, it perhaps leaves too much ambiguity." 5) The currently proposed draft of MOD-025-2 Attachment 1 includes an exemption for Nuclear Units from Reactive Power capability verification at minimum Real Power in paragraph 2.2.3. A similar caveat should be added to MOD-032-1 Attachment 1 regarding Steady State data requirements in item 3b: For Nuclear Units, modeling values for maximum and minimum Reactive Power at minimum Real Power output are not required to be validated by staged performance testing.
No
Benchmarking planning models to real time snapshots can be an exercise in futility based on the large number of variables in the models (loads, topology, gen. dispatch, interchange, etc.) and the limited access to real time data from neighboring areas that can be translated into the planning model for a selected snapshot. An alternative approach would be for the RC and TOP to benchmark operations planning models to real time state estimator snapshots, and have the RC and TOP work with their associated PC and TP to address any particular model concerns identified.
Group
SERC Planning Standards Subcommittee (PSS)
Jim Kelley

No
Standard MOD-032-1 should also be applicable to Distribution Providers, who would provide data for facilities <100 kV which would be included in the models. Also, the Distribution Provider provides load forecast data for use in model development, as well as short circuit data for transformer connections to the transmission system that serves network subtransmission facilities. With respect to short circuit data – there is no need for an interconnection-wide short circuit model. Further, existing short-circuit models contain considerably more detail than a typical powerflow model, making reconciling bus numbers and names between short-circuit and powerflow models difficult or impossible. Therefore, while both short-circuit and powerflow models are needed for different aspects of system analysis, the two types of models do not need to be mutually compatible with each other. Therefore, R4 in MOD-032 should be limited to powerflow and dynamics models. Other specific comments regarding short-circuit model data: 1) Why do planning horizon cases need negative and zero sequence data? Three phase faults pose the greatest challenge to breaker interrupting capability which addresses TPL-001-2 R2.3 & R2.8 and FAC-002-1 R1.1.4 (we know that phase to ground fault is somewhat higher at many plant switchyards, but the breaker single phase capability generally sufficiently exceeds that slight increase.) At the very most GSU zero sequence and generating plant outlet line Zo are needed for station grounding purposes or to confirm our first sentence; we recommend case handling this at the time of a connection study or major expansion (e.g. line or generator addition) instead of requiring this detail annually. Zero sequence mutuals are not needed. And for such planning studies negative sequence assumed equal to positive sequence is close enough. 2) Application Guide says they don't want to change present data collection efforts. In our case, for short circuit models, these are handled via the Regional Entity, not the Planning Coordinator. 3) Please clarify what 'all applicable elements' are for short circuit in Attachment 1. At the very least do so in the Application Guide. 4) The treatment of detailed data for older units should be addressed. The use of non-detailed synchronous generator or condenser modeling should be permitted for units with nameplate ratings less than or equal to 50 MVA (small units) for specific circumstances, including: a) detailed data is not available because the manufacturer is no longer in business, detailed data is not available because the unit is older than 1970. This criteria matches that of the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual, Version 10 (10 Jul 2013, Section 9.2, p. 37). Unconventional data requests that would require reverse/extensive engineering techniques to fulfill should also be addressed. Attachment 1, dynamic data items 2, 3, and 4 should be subparts of item 1 as they only apply to synchronous generators. Parts of the data request are duplicative with existing standards and other standards currently under development. a) MOD-026-1 has been filed with FERC for approval - it includes requirements for the GO to provide to the TP the model information listed in Attachment 1, dynamic data items 2, 3, and 4; b) MOD-025-2 has been filed with FERC for approval - it includes requirements for the GO to provide to the TP the model information listed in Attachment 1, steady-state data, items 3a, 3b, and 3c; c) approved standard VAR-002-2b, R4 already requires the GO to provide the TOP and TP with transformer data listed in Attachment 1, steady-state data, items 6b, 6c, and 6d. Attachment 1, steady-state data, Item 3d does not belong in the GO, RP category. The regulated bus and voltage setpoint is not

provided to the GO by the TOP. VAR-001-2. R4 requires the TOP to provide this information to the GOP, not the GO. We suggest that the TOP be added to MOD-032 to require this information be provided by the TOP directly to the TP. 5) What information or data would be provided by the BA, LSE, or TSP for short circuit modeling purposes (Attachment 1 table, short circuit item #3)? If none can be identified, these entities should not be applicable. 6) Resource planners aren't the appropriate entity to provide future steady-state, dynamics, or short-circuit data (Attachment 1). The Generator Owner should be responsible, once the project is announced, even for the future generator data. This data should be part of the generator interconnection process. 7) The phrase 'Other information requested by ….' Appearing in Attachment 1 is still too open ended, giving a route for requesting copious amounts of modeling data, for powerflow, dynamics, or short-circuit models, and wasting valuable resource time.
No
It would appear that, with comparison of a Planning Coordinator's portion of the existing system in a dynamic model to actual system response, as described in R1.2, using a 'dynamic local event', there may be a contradiction implicit within the requirement. If the requirement is to verify the dynamic response of the ENTIRE Planning Coordinator's system, and the use of a major system disturbance for this purpose is not intended, then it could take a plethora of smaller dynamic local events spaced across the Planning Coordinator's portion of the system to provide sufficient event coverage of a Planning Coordinator's system for validation purposes. The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee (PSS) only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. 1. MOD-032-1 appears to duplicate or perhaps even conflict with MOD-026-1 as regards to excitation system dynamic modeling data and with MOD-027-1 for governor dynamic modeling data. MOD-032-1 directs in R1.2.3 that PCs and TPs are to specify the, "case types or scenarios to be modeled," but R2 of MOD-026-1 and MOD-027-1 already list acceptable verification methodologies, thereby fully addressing this issue. R3 of MOD-032-1 describes how to deal with concerns over the validity of GO-reported data, despite the fact that the topic is already covered in R3, 5 and 6 of MOD-026-1 and R3 and 5 of MOD-027-1. Suggest that MOD-032-1 be fully reviewed and revised as required to ensure alignment with MOD-026-1 and MOD-027-1 data verification methodologies where applicable. 2. MOD-032-1 R1.2.2 calls for PCs and TPs to identify the, "level of detail to which equipment

shall be modeled." Such data requests can be difficult to satisfy for excitation system and governor dynamic models, depending on PCs and TPs specific requirements (which in this case are not yet identified). MOD-026-1 and MOD-027-1 have the same open level of detail issue, and therefore do not help address this MOD-032-1 issue. Additionally, PPL requests a reasonable match of actual and predicted excitation system and governor responses be required for no longer than 20 seconds. 3. There appears to be a duplication or conflict with other standards in that the real power, reactive power and aux load data to be reported per item 3a-c of the left-hand column of Att. 1 are already covered by MOD-025-2. 4. The voltage set point (item 3d in the left-hand column of Attachment 1) varies not only with modeling scenario changes (as denoted by the asterisk in MOD-032-1) but on a minute-by-minute basis as an operator adjusts the AVR to help keep the high-side voltage within bounds. It is not understood what value is required here – possibly the generator bus voltage corresponding to the scheduled system voltage per the GSU OEM's data sheets? 5. Ensure in Attachment 1 required data that tie busses for all tie points between TO's is included.
Yes
Group
JEA
Thomas McElhinney
Yes
No
Internal controls should be part of a good compliance program and not a requirement of a reliability standard. MOD033 will be very burdensome to the industry and provide little benefit.
Group
FirstEnergy
Cindy E Stewart
No
FirstEnergy (FE) has some concerns in the details as proposed in this draft. The following outlines our primary concerns and our comments also raise questions that we would like addressed by the drafting team. FE is concerned that the standard provides express permission to use "user-written" models. The entire modeling industry has been moving away from these and towards generic or industry agreed upon models for several years now, and the wording in MOD-032 is a big step backwards. ReliabilityFirst Corporation (RFC) has been publishing an Approved Models List (AML) for at least 6 years now, and all RFC members are expected to comply with the AML in their model selections. The primary argument against "user written" models is that they are not easily converted from PSS/E software (where most of these models reside) over to PSLF software which FE and other companies use. This standard moves in the opposite direction from where the industry seems to be heading with respect to "user written models". There is presently a large effort that is gaining momentum to eliminate all user written models, to ensure accurate modeling across all software platforms. Our observation is based on involvement we have experienced in the North American Transmission Forum (NATF) Models Practices Group (MPG). FE feels strongly that MOD-032 will only be acceptable when

"user-written" models are eliminated from the standard and only generic models are accepted. FE has had concerns regarding the development of the Interconnection-wide case, but after re-reading the MOD-032 document it seems this concern is somewhat covered by R4, but we are uncertain. "Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator’s planning area." FE understands that the Eastern Interconnection Reliability Assessment Group (ERAG) having already in place a Multiregional Modeling Working Group (MMWG) Procedure Manual could serve as the ERO’s designee for data as stated in Requirement R4. To this end, individual PC models used for their own area footprint studies should be consistently developed with the ERO’s designee’s practices to support the interconnection wide model. For the revised standard to work, FE believes the standard needs to specifically identify which entity will be developing the interconnect-wide model. There should also be direction that the entity developing the interconnection-wide model will provide their modeling requirements to the PC/TP. The PC/TP will then ensure that all the required modeling information will be obtained from the individual TOs and GOs.
No
FirstEnergy (FE) recognizes that Model Validation is an important function, and it’s good to see a Reliability Standard that supports this function. We support the validation effort, however, it should be limited to near-term (year one) models since longer term models may differ greatly in modeling assumptions such as load, generation dispatch and interchange flows. We do not see a need to benchmark a future year case, since there will be projects in future year cases that will directly cause variations from historical system data (state estimator case). Additionally, back office support personnel in a transmission operations center are better suited to perform the validation and maintain models that more closely mimic real-time conditions, particularly for the steady-state models. The validation of dynamic models will likely require support from a more traditional transmission planning engineering groups. However, with both the steady-state and dynamics validations there needs to be clear expectations on exactly which model year(s) is required to be assessed. MOD-033 is heavily dependent on the "documented data validation process" written by the PC. The standard is generally very vague and generic. The Standard provides very limited particulars and/or specifics. This raises a significant level of “fear of the unknown” and concern. In particular, FE understands that R1 is based on FERC Order 693... "In FERC Order No. 693, paragraph 1210, the Commission directed inclusion of “a requirement that the models be validated against actual system responses.” Furthermore, the Commission directs in paragraph 1211, “that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy.” However, FE believes for this to be included in a standard there needs to more clarity regarding which cases will be benchmarked, and to what parameters the case will be evaluated.
Group
Florida Municipal Power Agency
Frank Gaffney

No
FMPA continues to believe that that the data collection for long term planning models are a candidate for P81 treatment, as detailed in our comments during the last posting in September, and as summarized below. MOD-032 is duplicative of IRO-010 and TOP-003-2. All applicable entities need to submit the same data to the RC and TOP in accordance with those standards, with the exception of 10 year load forecasts, planned resources and planned transmission upgrades. Such planning information is not important to reliability except for purposes of adequacy, which is specifically excluded from Section 215 of the Federal Power Act. As such, the same goals of creating databases for long term planning purposes can be accomplished through mandatory data requests for purposes of NERC and regional annual assessments. FMPA recommends that the MOD-010 through -015 standards be retired and replaced with mandatory data requests and a process to create the interconnection wide databases outside of the standards.
No
FMPA continues to believe that the wrong models are being compared/validated within the proposed MOD-033 standard, as also described in our comments for the last posting in September. Long term planning models cannot be compared / validated to real time models because they are at least a year off and planning models cannot be accurate to real time. In order to compare/validate a planning model, one must first strip out everything planning related and make it an operating model. TOPs and RCs use operating models for current day, next day and seasonal studies; these are the models that ought to be validated / compared to serve a reliability purpose within the Section 215 construct, not the planning models. Yes, it is good business practice to compare planning models to operations; but, there is no reason to regulate that business practice through mandatory NERC standards when it serves no reliability purpose that is under the scope of Section 215. In addition, FMPA has comments on the RSAW. In the Note to Auditor, it states: “The extent of the Compliance Assessment Approach procedures described above to be applied will be based on the auditor’s perceived risk of the entity and compliance with this requirement to the reliability of the Bulk Electric System. In cases where risk is lower, the auditor may simply review the most recent comparisons or analyses versus when risk is higher, the auditor may require multiple comparisons or analyses to gain comfort that data validation processes were implemented.” Such exercise of discretion should not be completely unguided. FMPA suggests replacing “auditors perceived risk” with “auditor discretion as guided by established risk assessment guidance” or something to that effect.
Individual
Don Cuevas
Beaches Energy Services
Agree
Florida Municipal Power Agency (FMPA)
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.

No
Comments for MOD-032-1 (1) In Attachment 1 Data Reporting Requirements, the SDT listed in the table the information that is required to effectively model the interconnection transmission system in steady-state, dynamics, and short circuit. Seminole is seeking clarification for those items that include the terminology “(For future planed resources only),” in that these terms only apply to the Resource Planner (RP), i.e., Item 1 under “dynamics” of MOD-032-1 Attachment 1 includes both GO and RP: 1. Generator [GO, RP (for future planned resources only)] Seminole requires clarification that the caveat for future planned resources only applies only to the RP function and not the GO function. The same question exists for other items with the same formatting, i.e., limitations in parenthesis. (2) MOD-032-1 is applicable to Balancing Authorities, however, Seminole fails to see any specific identifiable action for which a Balancing Authority is responsible for within the Standard. Throughout the proposed Standard, it appears that the Balancing Authority is merely attached to Requirements as some sort of catch-all, in case there is an action the Standard Drafting Team may be forgetting. For example, in Attachment 1, the Balancing Authority is only assigned to the last item in each column that states “[o]ther information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, …].” Seminole fails to see why this proposed Standard should be applicable to Balancing Authorities and requests that the Balancing Authority function is removed from the Standard.
No
Comments for MOD-033-1 (1) Requirement R1 requires the comparison of models to actual system behavior. Along with the comparison, the registered entity is required to develop (1) guidelines for unacceptable differences and (2) guidelines to resolve differences between the comparison. Seminole requires clarification on what is meant by “guidelines.” Are guidelines merely “guides,” akin to suggested routes, or are they enforceable processes? For example, if an entity does not follow the guideline, is that a violation of this Requirement? (2) Requirement R1 requires the comparison of models to actual system behavior. Along with the comparison, the registered entity is required to develop (1) guidelines for unacceptable differences and (2) guidelines to resolve differences between the comparison. Seminole requires clarification on what is meant by “unacceptable differences” and how this section will be enforced. For example, can an entity say that 90% difference is unacceptable with the reasoning that anything less than 90% difference needs evaluation and may not be “unacceptable” under certain circumstances? In addition, from the audit/enforcement side, Seminole has serious concerns that registered entities may have very different values for unacceptable differences and how these scenarios will be audited. Seminole reasons that the SDT needs to provide quantitative or qualitative factors for acceptability or delete this Requirement. (3) The Rationale and Application Guidelines for Requirement R1 state that the Requirement lists “criteria” by which to develop procedures for validation. Seminole believes that Requirement R1 lacks criteria, and that this lack of criteria opens registered entities up to possible enforcement actions as the Requirement is not clear enough on what is “unacceptable,” what “needs” to be considered during comparisons, i.e., system load, transmission topology, etc., and many other parameters. This is a very vague Requirement and appears to be somewhat unenforceable on many facets. (4) In the Application Guidelines

section of the Standard, the SDT states that the PC “should” consider the following criteria for Requirement R1: a. System load; b. Transmission topology and parameters; c. Voltage at major buses; and d. Flows on major elements. The SDT states an entity “should” consider these criteria. It appears that an entity does not “need” to consider any of this criteria if they do not wish to consider them. Seminole reasons that this Standard is going to cause many serious issues with enforceability during audits as this Standard actually “requires” very few things. (5) This entire Standard includes language such as “should” and “may.” Seminole reasons that this Standard should be deleted and developed into a NERC guidance document, white paper, etc (i.e., some type of guidance).
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
No
The treatment of detailed data for older units should be addressed. The use of non-detailed synchronous generator or condenser modeling should be permitted for units with nameplate ratings less than or equal to 50 MVA (small units) for specific circumstances, including: a) detailed data is not available because the manufacturer is no longer in business, detailed data is not available because the unit is older than 1970. This criteria matches that of the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual, Version 10 (10 Jul 2013, Section 9.2, p. 37). Unconventional data requests that would require reverse/extensive engineering techniques to fulfill should also be addressed. Attachment 1, dynamic data items 2, 3, and 4 should be subparts of item 1 as they only apply to synchronous generators. Parts of the data request are duplicative with existing standards and other standards currently under development. a) MOD-026-1 has been filed with FERC for approval - it includes requirements for the GO to provide to the TP the model information listed in Attachment 1, dynamic data items 2, 3, and 4; b) MOD-025-2 has been filed with FERC for approval - it includes requirements for the GO to provide to the TP the model information listed in Attachment 1, steady-state data, items 3a, 3b, and 3c; c) approved standard VAR-002-2b, R4 already requires the GO to provide the TOP and TP with transformer data listed in Attachment 1, steady-state data, items 6b, 6c, and 6d. Attachment 1, steady-state data, Item 3d does not belong in the GO, RP category. The regulated bus and voltage setpoint is not provided to the GO by the TOP. VAR-001-2. R4 requires the TOP to provide this information to the GOP, not the GO. We suggest that the TOP be added to MOD-032 to require this information be provided by the TOP directly to the TP.
Individual
Karen Webb
City of Tallahassee Electric Utility
Yes
No

R1.2 –The standard should provide guidance as to the scope of an acceptable event and parameter better defining the term local. R1.3 The language does not provide for consistency across differing PCs in a geographic region (see comment R1.2) 1.4 – The language does not provide for consistency across differing PCs in a geographic region (see comment R1.2)
Individual
Ashley Stringer
Oklahoma Municipal Power Authority
No
In reference to Attachment 1 there needs to be clarification on which Generating Units are required to provide both the steady-state and dynamics data. It is currently unclear as to which Generating Units are subject to this Attachment. Is it only units that meet the 20MW individual/75 MW gross plant and touch the BES, or is it all generating units? It is not currently possible to determine station service auxiliary load on small emergency diesel generators less than 3.5 MW individual/8.2 MW gross plant. OMPA has attempted metering the total auxiliary load of each plant, and there simply is not enough load to accurately be depicted by metering CTs, let alone trying to meter the individual auxiliary of each unit.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
ATC believes additional dispersed (interconnection point by interconnection point) forecast Demand data is required for system modeling, reliability studies, and assessments. This data requirement could reside in MOD-032, and it is recommended to be added to MOD-032. This concern was addressed in MOD-016 and has not been included in either MOD-031 or MOD-032. To remedy the lack of point by point forecast demand, ATC recommends modifying the second item listed in Attachment 1 to ‘2. Interconnection Point Demand2’. The second footnote that further defines this data reporting requirement should be changed to ‘For purposes of this item, Interconnection Point Demand, is the demand at each interconnection point(s) for each bus under item 1 that is identified by a Transmission Owner as a load serving bus. An LSE is responsible for providing this information generally through coordination with the Transmission Owner.’
Yes
Individual
Michelle D'Antuono
Occidental Chemical Corporation (Ingleside Cogeneration LP)
Yes
From our perspective as a Generator Owner, Ingleside Cogeneration believes MOD-032-1 adds precision to the data specification that we are required to support. In addition, it is clear that the drafting team has made a concerted effort to ensure consistency with the Generation Validation and other NERC standards – that also require the submission of modeling data

needed for BES planning purposes. Both qualities of MOD-032-1 will improve the chances that we and other GOs can provide the requisite data in the desired format and expected time frames.
Yes
However, Ingleside Cogeneration is concerned that an auditor's expectations around the accuracy of simulations to actual system performance should be tempered. As the complexity of the component models increase, so does the likelihood of non-convergence at the system level. It may take several iterations before a good approximation is reached – and may not converge under all operating scenarios. We agree that the process should begin, but would like to see a reasonable risk-based approach to compliance to account for the uncertainty in the technology.
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
No
R1.2 –The standard should provide guidance as to the scope of an acceptable event and parameter better defining the term local. R1.3 The language does not provide for consistency across differing PCs in a geographic region (see comment R1.2) R1.4 – The language does not provide for consistency across differing PCs in a geographic region (see comment R1.2)
Individual
Roger Dufresne
Hydro-Québec Production
Yes
We need to have an equivalent of this: MOD-013-1 R1.2.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.
Yes
Individual
Joe O'Brien for Lynn Schmidt
NIPSCO
No
For MOD-032, Data for Power System Modeling and Analysis, there are two primary reasons to vote no: The first is that under MOD-032, the responsibility for coordinating model building passes from the regional reliability organization, RFC, to the planning coordinator, MISO. For NIPSCO, developing accurate and usable models requires close coordination with the two largest neighboring interconnected utilities having the greatest impact on NIPSCO, ComEd and AEP. NIPSCO, COmEd, and AEP are all in the same RRO, RFC. Having RFC as our model building coordinator has greatly facilitated our model building efforts. Both in terms of quality and

quantity, the present arrangement has resulted in a smooth and coherent exchange of data and coordination in the development of models. Under MOD-032, this high level of coordination and cooperation that exits today will be lost to the detriment of NIPSCO. NIPSCO's model building will be coordinated through MISO, while the model building efforts of CE and AEP will be coordinated through PJM. This separation into two different coordinators can only hinder model building and eventually lead to poorer models. If NIPSCO were in the middle of MISO instead of on the boundary with PJM this might not be a concern, but we're on the boundary with PJM. The second is that under MOD-032, generation owners will submit their data directly to the planning coordinator, MISO, instead of submitting the data to the transmission planner, NIPSCO. Presently, when the generator owners submit their data directly to NIPSCO, it gives us the opportunity to review their data for accuracy and consistency prior to inclusion in any model. NIPSCO and other transmission planners/owners have an incentive to review generator owner data as they will experience the greatest impact of incorrect modeling. MISO will not be able to achieve this level of review of generator owner data, nor will they have any incentive to do so.
No
For MOD-033, Steady-State and Dynamic System Model Validation, there is one primary reason to vote no: While model validation is a laudable goal, the proposed approach is way over the top. Checking data every two years is a totally unnecessary and unproductive expenditure of resources. Having been involved in prior data validation efforts, including RFC's System Snapshot in 2005, once every ten years is a much more realistic and productive approach. Model validation every two years is like checking your temperature every two minutes. Some may believe that model validation every two years leads to models that are perfect with 100% accuracy 100% of the time, but this is an unrealistic and unattainable goal.
Group
ACES Standards Collaborators
Ben Engelby
No
(1) We have concerns with the modification to Requirement R1. In the previous draft, there was an issue that multiple parties (i.e. Planning Coordinator and Transmission Planner) would be subject to R1 by having the words “in conjunction with.” In the instant draft, the requirement now uses the words “and…jointly.” The compliance outcome is the same, even though the words changed. We cannot support a standard that requires multiple parties to develop reporting procedures and data requirements and ultimately makes the each entity’s audit outcome dependent on another enitity’s audit outcome. This audit approach is clearly documented in the “Note to Auditor” section of R1 for the MOD-032-1 RSAW. This is not a practical approach for compliance purposes. (2) Planning Coordinators should already have agreements in place with its Transmission Planners for providing data. It is unnecessary to include both functions as the responsible entities for compliance. Including only the PC as the applicable entity is an equally efficient and effective alternative for this requirement. (3) For R2, we disagree with the inclusion of the Transmission Planner in requirement R1, therefore we also disagree with including the TP in R2. (4) For R3, part 3.2 is an administrative requirement

that meets multiple Paragraph 81 criteria including B1 – Adminstrative, B2 – Data Collection/Data Retention, and B4 - Reporting. If Part 3.2 persists, we request that the drafting team provide substantial justification for why it does not meet these P81 criteria. (5) For R4, if the PC is the responsible party for submitting the models to the ERO, then why is the PC not the sole entity responsible for R1? There are inconsistent responsible parties throughout the standard. (6) The list of functional entities in R2 should be reviewed carefully against the functional model for appropriate applicability to avoid unnecessary compliance burdens. Inclusione of some of the functional entities is unnecessary and may actually be duplicative. What data is expected to be provided by a BA that a GO would not already provide? Load forecast? If so, what data would an LSE provide that the BA does not already provide? The only information that an LSE would have is load forecast information. The RP may also have to provide this information. The application guidelines section should explain what data these entities are expected to provide. (7) R2 is partially duplicative of the proposed MOD-031-1 R2. MOD-032-1 R2 will require reporting Demand among other data to the PC. MOD-031-1 R2 will require the same data reporting. As a result, it is also partially duplicative with MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1. This redundancy should be removed either in this proposed standard or the MOD-032-1 proposed standard. (8) Some of the entities listed in requirements R2 and R3 may not be hierarchically part of a PC or TP. For example, the BA is an operating entity. Per the Functional Model, does it have a PC or TP. It clearly has an RC but we do not believe it is perfectly clear that it does have a PC or TP. Rather, the TO would be the entity to have a relationship with the PC or TP. If this hierarchical relationship does not exist between some of the entities listed and the PC or TP, this would make the use of “its Planning Coordinator” inconsistent with the Functional Model. (9) We are very supportive of the language in the RSAW for R2 and R3 in the “Note to Auditor” section that may contact the PC or TP to determine if the applicable entity has satisfied compliance. However, we think this should be strengthened to state the that the auditor must make this contact. It is really the most effective way to determine if data was provided. (10) We are also supportive of the language in the RSAW for R4 that NERC should verify with ERO personnel whether the PC has provided the information. It is the most effective and efficient way to determine compliance. However, we think the note should be strengthened to be clear that ERO personnel must also demonstrate that they made repeated attempts to ask the PC to provide the data if a deficiency was determined in the data. In other words, the PC and ERO should be working together to ensure data is provided timely and satisfactorily and the compliance checks should reflect this.
No
(1) For Requirement R1, we have concerns that Planning Coordinators will have different data validation processes, which will lead to inconsistent validation guidelines. Some entities in different regions may have different PCs and will need to perform different activities to be in compliance with the standard. (2) For Requirment R1, Parts 1.1 and 1.2, what is the technical justification for performing simulations once every 24 months? Without technical justification for the 24 months, this timeline appears to be arbitrary. (3) For Requirement R1, Part 1.3, needs to be modified to remove “unacceptable differences in performance” because this language is ambiguous. The compliance guidance states that an entity will be required to

include documented guidelines to determine whether the differences are unacceptable. These guidelines are subjective and open to multiple interpretations as to what unacceptable differences in performance actually are and there could be inconsistent application among PCs. (4) For Requirement R2, this requirement meets Paragraph 81 criteria because it is administrative, focuses on data collection activities, and requires periodic updates that do not directly support reliability. This requirement should be struck in its entirety. (5) In regard to the final statement by NERC Compliance in its guidance document, what training will compliance develop? Is this type of training for industry? We need additional guidance from NERC compliance on how this standard will be audited. Is this training the type how to comply with the standard? This would be helpful to industry in preparing for implementing a new standard. However, we would strongly disagree that this should be a standard that requires enforceable training requirement. (6) Thank you for the opportunity to comment.
Group
Duke Energy
Colby Bellville
No
Dynamic modeling expertise is historically a transmission planning responsibility. Unlike AVR/Exciter models which were developed to reflect a specific OEMs voltage control and excitation system, there is not a clear understanding by GOs of how speed governor/plant frequency response models are used to support reliability and the technical issues related to this are not well understood by plant designers and OEMs. Based on recent discussions, the expertise in the industry related to this issue ranges from weak on the planning side to non-existent on the generation side. The concept of model ownership has not been thoroughly vetted by the generation industry, whose engineering does not maintain expertise in Dynamic Grid Modeling. We continue to see discrepancies in how plants response vs. what the models that were provided by the plant designers, predict. There are also problems with a lack of common definitions understanding of Normal vs. Emergency MW plant ratings, which are inherent in the understanding of how a unit may respond to frequency dips when operating at or near normal MW ratings. A suggested approach would be to require the system analysts to take a lead role in defining plant responses to frequency transients and require the GO/GOP function to support the development of the models to meet the needs of the analysts and to capture data that can be used by the analysts to validate the models
No
Duke Energy suggests adding Generator Owner (GO) as one of the applicable functions to Requirement 2. As written, we believe there is a potential gap in requesting dynamic data and believe the addition of GO could close this gap. Also in Requirement 2, Duke Energy suggests allowing for an extension of the 30 day timeframe for providing actual system behavior data, as long as all parties involved agree to the time extension.
Group
BC Hydro and Power Authority
Patricia Robertson

Yes
No
1. The terms “consistent validation” and “collection of accurate data” should apply to the real-time frame and not to the planning horizon. Models once validated should be used to analyze the reliability of the interconnected transmission system as per MOD-032. 2. Efforts should be centred on validating the data used for steady state and dynamic analyses in the real-time environment (existing system) and its comparison with actual system responses. 3. In terms of data models, there are issues not yet well addressed by the industry in order to perform “consistent validation”. These are: a) typical or estimated data models, b) generic data models and c) proprietary data models.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM supports the consolidation of the MOD standards included in this project. There is a concern regarding the scope of R4 specific to the responsibility and potential resource burden put on the PC to provide a potentially unknown number of models to the ERO to support interconnection-wide cases they want to create. PJM supports additional language in this requirement to give the PC more control over the types of cases and total number of cases requested by the ERO.
Yes
Individual
Teresa Czyz
Georgia Transmission Corporation
Yes
At present, data requirements and reporting procedures have already been written by most of the RRO’s, which establish consistency across the interconnection. GTC’s concern is that there is no requirement in this standard for the ERO or its designee to provide data requirements and reporting procedures to the PCs or other affected entities for interconnection-wide models. R1.2 requires the PCs to develop their own data requirements in accordance with “Specifications of the following items consistent with procedures for building the interconnection-wide cases: …..” The assumption is that PCs will continue to coordinate model data requirements following the ERO’s or their designee’s “Procedural Manual” using the structure that has been in place for some time. IE. SERC’s DBU process. But what happens if the structural model changes or the procedural manuals change? Under FERC order 693 it states: “MOD-014-0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of solved Interconnection-specific steady-state models.” And yet R4 requires no “coordination” or “joint development” or “maintenance” between ERO or their designee and PCs for interconnection-wide models. GTC believes that there should be an additional requirement for the “ERO or its designee”. It would require the ERO or its designee to submit model data requirements and reporting procedures

to the PCs and other affected entities. This would ensure data consistency and data reporting timeliness.
Yes
Group
SPP Standards Review Group
Robert Rhodes
Yes
We appreciate the effort that the drafting team has put into developing MOD-032-1 and believe the standard is an improvement over those in existence today. In the 2nd sentence of the Rationale Box for R4, a reference is made to the three Interconnections. We would suggest deleting the 'three' since there are actually four Interconnections. We noted that this change has already been made in the Guidelines and Technical Basis section. Insert 'made' in the Severe VSL for R4 such that it reads: 'The Planning Coordinator made available the required data…' This is consistent with the other VSLs for R4. In the next to last sentence in the 3rd paragraph on Page 22 of the Guidelines and Technical Basis section, we suggest the following wording for clarification. 'This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the original entity.'
Yes
Group
Colorado Springs Utilities
Kaleb Brimhall
No
Thank you Standard Drafting Teammates for all of your efforts. i. We disagree with the application of this Standard to individual Planning Coordinators within WECC. WECC already produces a Data Preparation Manual which defines the data submittal process for building system models. Compliance with this manual by all participating WECC entities ensures the data consistency and integrity necessary for the most accurate modeling results. ii. We believe that WECC is the authority that should manage the development of accurate WECC-wide system models. Should this standard pass as is, we further believes that a specific WECC variance should be made a part of the Standard. The variance would define the development of technical model data requirements and reporting procedures to be responsibility of WECC rather than of the individual PCs within WECC. iii. We also re-iterates the concerns brought up by industry to WECC in the past concerning the lack of clarity within the WECC region concerning planning coordinators. Many entities within WECC do not have a planning coordinator. The issue of Planning Coordinators must be resolved for this standard to be applied as written in the WECC region.
No
Thank you Standard Drafting Teammates for all of your efforts. i. We disagree with the application of this Standard to individual Planning Coordinators within WECC. WECC already

produces a Data Preparation Manual which defines the data submittal process for building system models. Compliance with this manual by all participating WECC entities ensures the data consistency and integrity necessary for the most accurate modeling results. ii. We believe that WECC is the authority that should manage the development of accurate WECC-wide system models. Should this standard pass as is, we further believes that a specific WECC variance should be made a part of the Standard. The variance would define the development of technical model data requirements and reporting procedures to be responsibility of WECC rather than of the individual PCs within WECC. iii. We also re-iterates the concerns brought up by industry to WECC in the past concerning the lack of clarity within the WECC region concerning planning coordinators. Many entities within WECC do not have a planning coordinator. The issue of Planning Coordinators must be resolved for this standard to be applied as written in the WECC region.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
No
City of Austin dba Austin Energy encourages the SDT to revise the requirement (R1 part 1.2) from validate dynamic models "at least once every 24 calendar months" to validate dynamic models "at least once every 60 calendar months."
Individual
Robert W. Roddy
Dairyland Power Cooperative
No
We have not seen any technical justification for an industry-wide short circuit model. We believe this will add workload on our staff without any significant benefit to DPC or to our region.
Yes
Group
MRO NSRF
Russel Mountjoy
No
The NSRF has compliance concerns on R1, specifically, "the PC and TP shall jointly develop…". From the RSAW in the Notes to the Auditor: "Auditor will seek evidence that the entity jointly developed the requirements and reporting procedures as required." The weight of compliance has the potential to undermine the data requirement development. What is important is the data requirements and data. Attachment 1 concerns: 1. The DC transmission item in the powerflow section of Attachment 1 should be more specific in its requirements, such as Power order, Firing Angle, Scheduled Voltage, Additional Line parameters not mentioned above, and Converter transformer parameters at rectifier and inverter. 2. The dynamics data section of

Attachment 1 should be expanded to reflect the detail contained in the powerflow section of Attachment 1
No
Currenlty the NERC registry has 80 registered PCs and 185 TPs. R1 states that each PC needs to compare the performance of its portion of the system to actual system behavior. With such a high number of PCs, the degree of variables makes for an almost impossible task to identify where descrepancies in model validation occur. 24 months is too short of an interval to perform the steady state and dynamic model validation. Suggest an interval of 60 months for the validation period. 3. General comments: MOD-032-1 & MOD-033-1 do not answer the question on who is responsible for the actual building of the model. Data is to be collected and a model is to be verified, however, who is required to build the model? The ERO, the interconnections, the Regional Entities? Under what requirements are the models to be built? Currently the NERC registry has 80 registered PCs and 185 TPs. NERC and industry need to re-assess the continent-wide model development process. All PCs or TPs should have access to the ERO models regardless of their relationship with the designee. Suggest a requirement stating that the ERO (or designee) models are available by request to any PC or TP. Currerntly there is not a process for the ERO to make the models available. ERAG is not the NERC designee and is a separate organization of 6 regions. Modifications to the ERAG charter should it become the designee need to be made so that all NERC registered entities have access to the information.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PSS
Group
PacifiCorp
Ryan Millard
Yes
Yes
Group
Bonneville Power Administration
Andrea Jessup
Yes
BPA reiterates concerns about providing zero-sequence data in the powerflow. It will require an extensive amount of effort on BPA’s part to parse the data from Aspen One-liner and include it with the powerflow model, and BPA doesn't know of anyone within WECC who is currently using the powerflow model to analyze single phase faults. Additionally, the guidelines at the back of MOD 32 state: “The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both

what is already in place or what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).” However MOD 32 does not assign any responsibility to the ERO designee (in this case WECC). Per MODs 11 & 13 our current processes and procedures require the Regional Reliability Organization (RRO) to jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The current version of MOD 32 removes all references to the RRO and does not transition any of the responsibility to the ERO designee. With the responsibility of data coordination being solely with the Planning Coordinators (PC), with no requirements to coordinate with each other, how are we going to keep our established processes and maintain a level of data quality that facilitates the building of interconnection-wide cases? BPA suggests that the ERO designee have the responsibility to jointly coordinate the development of the data requirements and reporting procedures for that Interconnection with the PC(s) to maintain a level of data quality that facilitates the building of interconnection-wide cases.
Yes
BPA reiterates concern over the requirement to align the planning model representation of the system to what is occurring “real time”. The topology used to plan a case is based upon peak seasonal loads and the assumption that all lines are in their “normal operating state”. This is not generally the case in the real world. The topology and the load (and the real time generation pattern) are likely to be very different. The state estimator model could possibly be utilized as an interim step for determining the accuracy of a computer model representation to real time responses of the system. But the state estimator is not totally aligned with the powerflow model as one is bus/branch − the other breaker/node.
Individual
Patrick Farrell
Southern California Edison Company
Yes
SCE would like to thank the drafting team for its consideration of previously submitted comments. SCE agrees with the approach of MOD-032 as revised. In particular, we support the use of the word “reflecting” in R4. Allowing the PC to adjust data as necessary adequately supports the process of developing usable interconnection-wide models for use in accurate and reasonable assessments of the interconnected electrical grid, ensuring that long-term reliability is maintained and adequately planned. We thank the drafting team for the opportunity to comment and the efforts of the drafting team to construct a performance-based revised standard.
Yes
SCE would like to thank the drafting team and NERC for providing the opportunity to comment on the revised modeling validation standard. We continue to support a validation standard that allows the Planning Coordinator to identify potentially inaccurate models and develop its own criteria or threshold for the identification of potentially incorrect models.