UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _______**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS
MOD-032-1 AND MOD-033-1

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standards MOD-032-1 – Data for Power System Modeling and Analysis and MOD-033-1 – Steady-State and Dynamic System Model Validation. NERC requests that the Commission approve proposed Reliability Standards MOD-032-1 and MOD-033-1 (Exhibit A) as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of (i) the associated Implementation Plan (Exhibit B), (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and F), and (iii) the retirement of the currently effective Reliability Standards MOD-010-0 and MOD-12-0 and

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1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* (the "NERC Glossary"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

the withdrawal of pending Reliability Standards MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 (collectively, the "Existing MOD B Standards"), [5] as detailed in this Petition.

As required by Section 39.5(a)[6] of the Commission's regulations, this Petition presents the technical basis and purpose of proposed Reliability Standards MOD-032-1 and MOD-033-1, a summary of the development history (Exhibit G) and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[7] (Exhibit C). The NERC Board of Trustees approved proposed Reliability Standards MOD-032-1 and MOD-033-1 on February 6, 2014.

I. EXECUTIVE SUMMARY

Proposed Reliability Standards MOD-032-1 and MOD-033-1 are designed to replace, consolidate and improve upon the "Existing MOD B Standards" in addressing system-level modeling data and validation requirements necessary for developing planning models and the Interconnection-wide cases[8] that are integral to analyzing the reliability of the Bulk-Power System. Models are the foundation of virtually all power system studies used to assess the reliability of the Bulk-Power System. In particular, power system studies rely on models to predict system performance under various conditions. Calculation of operating limits, planning studies for assessments of new generation and load growth, and performance assessments of system integrity

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5 Of the six Existing MOD B Standards, only MOD-010-0 and MOD-12-0 were approved in Order No. 693. The other four Existing MOD B Standards were deemed "fill-in-the-blank" standards and were neither approved nor remanded but remain pending. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416, FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). As such, this Petition requests approval to retire MOD-010-0 and MOD-012-0 and withdraw MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1.

6 18 C.F.R. § 39.5(a) (2013).

7 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

8 "Interconnection-wide case" refers to a compilation of model information that represents an entire Interconnection.

protection schemes are examples of studies that depend on accurate mathematical representations of transmission, generation and load. If models are too optimistic, it could result in grid under-investment, unsafe operating conditions, and power outages. In contrast, pessimistic models can result in overly conservative grid operation and under-utilization of network capacity. It is thus vital that models, including all of their data, are complete, accurate, and up to date. The purpose of the proposed Reliability Standards is to establish comprehensive modeling data requirements, reporting procedures, and validation requirements necessary to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and the Long-Term Transmission Planning Horizon.[9]

Proposed Reliability Standards MOD-032-1 and MOD-033-1 were developed to address: (i) directives from Order Nos. 890[10] and 693[11] to modify the Existing MOD B Standards; and (ii) recommendations from a white paper drafted by the NERC Planning Committee's System Analysis and Modeling Subcommittee (the "SAMS Whitepaper") proposing improvements to the Existing MOD B Standards.[12] Consistent with Commission directives and the SAMS Whitepaper, the proposed Reliability Standards improve upon the Existing MOD B Standards by: (i) clarifying data collection requirements by clearly articulating "who" provides "what" data to "whom"; (ii)

9 As defined in the NERC Glossary, the Near-Term Transmission Planning Horizon is the "transmission planning period that covers Year One through five." The Long-Term Transmission Planning Horizon is defined as the "Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete."

10 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 290 (2007), order on reh'g, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

11 Order No. 693 at PP 1131-1222.

12 The white paper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, available at: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf.

expanding the coverage of the Existing MOD B Standards beyond steady-state and dynamics modeling data to include short circuit modeling data; (iii) providing a mechanism to address any technical concerns with the modeling data collected; and (iv) requiring the validation of steady-state and dynamics models against actual system responses.

As discussed below, proposed Reliability Standard MOD-032-1 consolidates the Existing MOD B Standards and requires, among other things, applicable registered entities (i.e., Balancing Authorities, Generation Owners, Load Serving Entities, Resource Planners, Transmission Owners and Transmission Service Providers) to provide steady-state, dynamics, and short circuit modeling data to their respective Planning Coordinators[13] and Transmission Planners to support the Interconnection-wide case building process for their Interconnection. Proposed MOD-032-1 creates a framework for collecting modeling data that supports existing practices for developing planning models and Interconnection-wide cases and is also flexible enough to accommodate any changes to those practices that become necessary or preferable over time. Proposed Reliability Standard MOD-032-1 establishes the Planning Coordinator and Transmission Planner as the functional entities obligated to develop modeling data requirements and reporting procedures that applicable entities in their planning area must follow. The Planning Coordinator is also responsible for making available models for its planning area to the ERO (or its designee), who, in turn, facilitates the development of the Interconnection-wide cases.

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13 As provided in the NERC Glossary, a Planning Coordinator is the same functional entity as a Planning Authority. Both are defined as "[t]he responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems." The Reliability Functional Model uses the phrase "Planning Coordinator" to refer to such entities while NERC's registration criteria uses the term "Planning Authority." Applicability Section 4.1.1 of the proposed Reliability Standards lists both Planning Coordinators and Planning Authorities to avoid confusion as to which registered entities are subject to the proposed Reliability Standards. As explained in Applicability Section 4.1.1, however, the requirements of the proposed Reliability Standards only use the term "Planning Coordinator."

Proposed Reliability Standard MOD-033-1 requires each Planning Coordinator to implement a documented process for performing steady-state and dynamics model validation. Implementation of validation processes in accordance with proposed Reliability Standard MOD-033-1 should result in more accurate steady-state and dynamics models for assessing the reliability of the Bulk-Power System. Specifically, the validation requirements will help promote better correlation between system flows and voltages in power flow studies and the actual values observed by system operators. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

For the reasons discussed in this Petition, NERC respectfully requests that the Commission approve the proposed Reliability Standards as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[14]

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14 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's procedural rules, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[15] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System and certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[16] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[17] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[18] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[19] and Section 39.5(c)[20] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

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15 16 U.S.C. § 824o (2006).

16 *Id.* § 824(b)(1).

17 *Id.* § 824o(d)(5).

18 18 C.F.R. § 39.5(a) (2012).

19 16 U.S.C. § 824o(d)(2).

20 18 C.F.R. § 39.5(c)(1).

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standards were developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[21] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[22] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. Overview of Power System Models

Bulk-Power System planning and operating decisions are based on the results of power system studies. These studies rely on power system models to predict system performance. In modeling a large power system (e.g., the Western or Eastern Interconnections in North America), there are three general categories of models that need to be developed:

1. *Transmission Systems*: This category consists of equipment needed to transmit power from generation to load, including, but not limited to, transmission lines, power transformers, and reactive power devices. The models often include equipment controls such as voltage pick-up and drop-out levels for shunt reactive devices.

[21] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[22] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

2. *Generating Unit*: This category includes the entire spectrum of supply resources, such as hydro, steam, and gas generators along with rapidly emerging wind and solar power plants. There is also a need for modeling distributed generation (e.g., solar, microturbines, fuel-cells, etc.).

3. *Load*: This category consists of modeling the electrical load on the system, which ranges from simple light-bulbs to large industrial facilities.[23]

As described in the Power System Model Validation White Paper, each of the above categories (transmission systems, generators, and load) can be represented by a steady-state (a.k.a powerflow) model to evaluate how those components perform under static conditions. This component level model development is accomplished by an accurate calculation of the impedances, ratings, and other parameters that will be incorporated into the full steady-state network model. Flexible AC transmission system ("FACTS") and high-voltage dc ("HVDC") transmission system facilities have steady-state model structures that can vary with the vintage of technology of the device being modeled and the operating mode of the device. For generation units, steady-state models represent impedance parameters, real and reactive power limits, and settings for voltage control at either the generator terminal bus or a nearby high-voltage bus. These models should use data, including the generator reactive capability, that have been validated through field tests or empirical evidence. Load is typically represented as constant real and reactive power. Constant current and constant impedance loads are also sometimes represented in steady-state models.

The individual component models are then combined into a complete system model for representing the steady-state behavior of an entire Interconnection (i.e., Interconnection-wide

[23] *See Power System Model Validation, A White Paper by the NERC Model Validation Task Force of the Transmission Issues Subcommittee*, at 6 (December 2010) (the "Power System Model Validation White Paper"), available at http://www.nerc.com/comm/PC/Model%20Validation%20Working%20Group%20MVWG/MV%20White%20Paper_Final.pdf.

cases).[24] Powerflow models of transmission systems usually represent only positive sequence quantities. Steady-state network models are also used for short circuit studies. These models include negative sequence and zero sequence network data in addition to positive sequence data.

Beyond the need for analyses of the steady-state behavior of the power system, it is crucial that the dynamic behavior of the system be analyzed as well. Models that represent the dynamics of components can also be developed for the categories listed above. The dynamics models represent the behavior of power plants and their controls, certain components of loads, power electronic transmission devices (i.e., FACTS and HVDC), and, for some studies, on-load tap changers, control schemes on shunt devices, remedial action schemes, and other similar control devices. The components in the powerflow model need to be matched with their corresponding dynamics models.[25]

Additionally, it is important to construct short circuit models to perform system protection analyses and support analysis at the seams between neighboring regions. Short circuit models are also used in conjunction with power flow and dynamics applications, for example, to calculate unbalanced fault shunt admittance for three-phase faults in dynamics simulations.

Models are used in both operating studies for setting real-time power transfer limits and planning studies for analyzing conditions at some time – possibly many years – in the future. Because of the importance of power system models, the models, including all of their data, must be accurate and up to date. As noted above, the use of inaccurate models could result in grid under-investment, unsafe operating conditions, and ultimately widespread power outages, such as

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[24] For some studies, remote parts of a large Interconnection sufficiently distant from the area of interest are represented using reduced-size models known as "equivalents."

[25] For additional information on power system models, see the Power System Model Validation White Paper at 6-8.

occurred in the summer of 1996 in the Western Interconnection,[26] or, conversely, overly conservative grid operation and under-utilization of network capacity. Therefore, accurate models are vital to reliable power system operation.

D. The Existing MOD B Standards

The Existing MOD B Standards are designed to address data requirements and reporting procedures for power system planning models for use in reliability analysis. In particular, they specify steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamics behavior of the power system within each Interconnection. The following is a brief description of each of the Existing MOD B Standards:

- *MOD-010-0* requires Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners to provide steady-state data, such as equipment characteristics, system data, and existing and future interchange schedules to the Regional Reliability Organization, NERC, and other specified entities.

- *MOD-011-0* requires the Regional Reliability Organizations to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection.

- *MOD-012-0* requires Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners to provide dynamics system modeling and simulation data, such as equipment characteristics and system data, to the Regional Reliability Organization, NERC, and other specified entities.

- *MOD-013-1* requires the Regional Reliability Organizations within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response of each Interconnection.

- *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.

- *MOD-015-0.1* requires the Regional Reliability Organizations within each Interconnection to coordinate and jointly develop and maintain a library of initialized (with no faults and disturbances) Interconnection-specific dynamics system models.

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26 *See* Power System Model Validation White Paper at 9-14.

In Order No. 693 the Commission approved MOD-010-0 and MOD-012-0[27] but deemed the other four Existing MOD B Standards "fill-in-the-blank" Reliability Standards and did not approve or remand MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1.[28] As such, MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 remain pending, although the Commission stated that it expected registered entities to comply with the "fill-in-the-blank standards" on a voluntary basis.[29]

The Commission also directed NERC to modify the Existing MOD B Standards, as follows:

- Modify MOD-010-0 through MOD-013-1 to include the Planning Coordinator as an applicable entity because the Planning Coordinator is "responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."[30]

- Modify MOD-010-0 to require the filing of all of the contingencies that are used in performing steady-state system operation and planning studies.[31]

- Modify MOD-010-0 to include Transmission Operators as an applicable entity because Transmission Operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation.[32]

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27 Order No 693 at PP 1146, 1176.

28 *Id*. at PP 1161, 1196, 1209, 1219. FERC referred to a proposed Reliability Standard as a "fill-in-the-blank standard" where the Reliability Standard required Regional Reliability Organizations, now called Regional Entities, to fill in missing criteria or procedures. *Id*. at PP 287-303. Due to concerns regarding the potential for such standards to undermine uniformity and the absence of certain criteria and procedures, the Commission stated it was not in a position to approve or remand those proposed Reliability Standards until the ERO submits further information.

29 *Id*. at P 297.

30 *Id*. at P 1155, 1162, 1184, 1199. Order No. 693 refers to Planning Authorities rather than Planning Coordinators. As explained above, a Planning Coordinator is the same functional entity as a Planning Authority and the proposed Reliability Standards use the term Planning Coordinator instead of Planning Authority. S*ee* s*upra* at n. 13.

31 Order No. 693 at P 1148.

32 *Id*. at PP 1154.

- Modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning.[33]

- Modify MOD-012-0 to require the Transmission Planner to provide the fault and disturbance lists.[34]

- Modify MOD-013-1 to permit entities to estimate dynamics data if they are unable to obtain unit specific data but require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.[35]

- Modify MOD-014-0 and MOD-015-0.1 to (1) include a requirement that the models be validated against actual system responses,[36] and (2) require 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.[37]

Additionally, in Order No. 890, the Commission directed public utilities, working through NERC, to modify Reliability Standards MOD-010 through MOD-025 to "incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date."[38] The Commission stated that "[t]his means that the models should be updated and benchmarked to actual events."[39]

In addition to these directives, in November 2012, the NERC Planning Committee's System Analysis and Modeling Subcommittee issued the SAMS Whitepaper recommending several improvements to the Existing MOD B Standards, including: (1) streamlining the Existing MOD B Standards; (2) adding short circuit data; (3) clearly identifying responsibility to provide

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33 Order No. 693 at P 1178.

34 *Id*. at P 1183.

35 *Id*. at P 1197.

36 *Id*. at P 1210, 1220.

37 *Id*. at P 1211, 1220.

38 Order No. 890 at P 290.

39 *Id*.

and receive data (i.e., who provides what data to whom); (4) including a provision on the acceptability of the data; (5) requiring specification and standardization of data format; (6) drafting the standard to be flexible enough to accommodate the development of new technology; and (7) ensuring that the data is shareable.

E. History of Project 2010-03 - Modeling Data (MOD B)

In February 2013, NERC initiated an informal development process to (i) address the outstanding directives from Order Nos. 890 and 693 to modify the Existing MOD B Standards, and (ii) consider the recommendations from the SAMS Whitepaper. Participants in this informal process were industry subject matter experts, NERC staff, and staff from FERC's Office of Electric Reliability. The informal group met numerous times between February 2013 and July 2013 to discuss the outstanding FERC directives, the recommendations from the SAMS Whitepaper, and, in light of their experience with the Existing MOD B Standards, ways to improve those standards. The informal group also conducted industry outreach to obtain feedback on possible improvements to the Existing MOD B Standards.

The participants in the informal development process proposed two new Reliability Standards to replace the Existing MOD B Standards: (1) a modeling data Reliability Standard that consolidates and improves upon the Existing MOD B Standards (MOD-032-1); and (2) a validation Reliability Standard to address the Commission's directives to include a requirement that models be validated against actual system responses (MOD-033-1). In drafting these proposed Reliability Standards, the informal participants sought to draft results-based standards that considered the improvements recommended in the SAMS Whitepaper.

Project 2010-03 - Modeling Data (MOD B) was formally initiated on July 18, 2013 with the posting of a Standard Authorization Request along with the draft Reliability Standards developed by the informal participants for a 45-day formal comment period and ballot. Following this posting, the standard drafting team of industry experts was formed, many of whom were participants in the informal process. As described further in Exhibit G, after an additional comment and ballot period for MOD-032-1 and two additional comment and ballot periods for MOD-033-1, the proposed Reliability Standards received the requisite approval from NERC stakeholders. The proposed Reliability Standards were approved by the NERC Board of Trustees on February 6, 2014.

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit C, the proposed Reliability Standards satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following section provides (1) the basis and purpose of the proposed Reliability Standards; (2) a description of the requirements in each of the proposed Reliability Standards; (3) a discussion of how the proposed Reliability Standards satisfy the outstanding Commission directives associated with the Existing MOD B Standards; and (4) a discussion of the enforceability of the proposed Reliability Standards.

A. Basis and Purpose of Proposed Reliability Standards

Proposed Reliability Standards MOD-032-1 and MOD-033-1 are designed to replace, consolidate, and improve upon the "Existing MOD B Standards" in addressing modeling data and validation requirements necessary for building planning models and the Interconnection-wide cases. As discussed above, to effectively study the reliability of the Bulk-Power System, the devices, equipment, and systems that comprise the Bulk-Power System must be modeled to capture how those devices, equipment, and systems perform under both static (i.e., steady-state) and dynamic conditions. Additionally, it is important to construct short circuit models to perform system protection analyses and support analysis at the seams between neighboring regions.

The purpose of the proposed Reliability Standards is to provide a mechanism for the collection and validation of the information required to effectively model the interconnected transmission system for both the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. The proposed Reliability Standards help ensure that power system models, including all of their data, are complete, accurate, and up to date. Collectively, proposed MOD-032-1 and MOD-033-1 improve upon the Existing MOD B Standards by: (1) clarifying and updating the data requirements and reporting procedures; (2) expanding the coverage of the Existing MOD B Standards to include short circuit data; (3) providing a mechanism for addressing technical concerns with the modeling data collected; and (4) requiring the validation of steady-state and dynamics models against actual system responses.

The following is a discussion of each of the proposed Reliability Standards and the requirements therein.

B. Requirements of the Proposed Reliability Standards

1. Proposed Reliability Standard MOD-032-1

Proposed Reliability Standard MOD-032-1, which merges the Existing MOD B Standards,[40] contains four requirements that collectively provide the framework for the collection of steady-state, dynamics, and short circuit modeling data that is necessary for building planning models and the Interconnection-wide cases. Proposed MOD-032-1 provides clear expectations for "who" provides "what" data to "whom" while also providing entities the flexibility to develop data requirements and reporting procedures that are appropriate to their specific circumstances and Interconnection. Proposed Reliability Standard MOD-032-1 creates the following framework:

[40] Exhibit D to this Petition is a mapping document showing the translation of the existing MOD B Standards to proposed Reliability Standard MOD-032-1.

- *Requirement R1* requires Planning Coordinators and Transmission Planners to jointly develop data requirements and reporting procedures for steady-state, dynamics, and short circuit modeling data for entities in their planning area.

- *Requirement R2* requires the registered entities that have the modeling data (i.e., data owners) to provide their data to their Planning Coordinator(s) and Transmission Planner(s) in accordance with the data requirements and reporting procedures developed pursuant to Requirement R1.

- *Requirement R3* provides Planning Coordinators and Transmission Planners an opportunity to coordinate with the data owners to address any technical concerns with the data provided under Requirement R2.

- Finally, *Requirement R4* obligates Planning Coordinators to make available models for its planning area reflecting the data provided to it under Requirements R2 to the ERO, or its designee, for use in creating the Interconnection-wide cases.

The following is a discussion of each requirement in proposed Reliability Standard MOD-032-1.

Requirement R1 sets forth the framework for developing the data requirements and reporting procedures necessary to support the model building process. Requirement R1 provides as follows:

> **R1.** Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include:
>
> **1.1** The data listed in Attachment 1;
>
> **1.2** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):
>
> **1.2.1** Data format;
>
> **1.2.2** Level of detail to which equipment shall be modeled;
>
> **1.2.3** Case types or scenarios to be modeled; and
>
> **1.2.4** A schedule for submission of data at least once every 13 calendar months.
>
> **1.3** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

Requirement R1 consolidates the concepts from the original data requirements from Reliability Standards MOD-011-0 and MOD-013-0 but establishes Planning Coordinators and Transmission Planners, as opposed to Regional Reliability Organizations, as the functional entities obligated to develop data requirements and reporting procedures that applicable registered entities in their planning area must follow.[41] Consistent with the Commission's directives in Order No. 693, the Planning Coordinator is the appropriate entity for developing the data requirements and reporting procedures "because [it] is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."[42] The inclusion of Transmission Planners is intended to ensure that Transmission Planners are able to participate in the development of the data requirements and reporting procedures given their role in maintaining planning models to assess reliability.[43]

Attachment 1 identifies (1) the type of steady-state, dynamics, and short circuit modeling data that must be provided to effectively model the interconnected transmission system, and (2) the functional entity responsible for providing each type of modeling data. Attachment 1 carries forward the types of steady-state and dynamics modeling data included in MOD-011-0 and MOD-013-0, respectively, covering the modeling data necessary to support the model building process for transmission systems, generating units, and load that are used to develop the Interconnection-wide cases.

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[41] By establishing Planning Coordinators and Transmission Planners, rather than Regional Reliability Organizations, as the entities responsible for developing the modeling data requirements and reporting procedures, proposed MOD-032-1 addresses the Commission's concern related to the "fill-in-the-blank" nature of certain of the Existing MOD B Standards.

[42] Order No. 693 at PP 1155, 1162, 1184, 1199.

[43] NERC's Reliability Functional Model lists the "maintenance of transmission system models (steady state, dynamics, and short circuit) to evaluate Bulk Electric System performance" as a task performed by Transmission Planners. *See Reliability Functional Model* at 24.

Compared to the Existing MOD B Standards, however, Attachment 1 adds specificity and clarity to the modeling data requirements, consistent with the recommendations in the SAMS Whitepaper.[44] Attachment 1 explicitly lists data items that are fundamental to powerflow analysis and notes which items vary with system operating states or conditions such that those items may have different data provided for different modeling scenarios. Similarly, Attachment 1 also lists fundamental data requirements of dynamics models and specifies that if a user written dynamics model is submitted in place of a generic or library model, the entity must include the characteristics of the model, including block diagrams, values, and names of all model parameters, and a list of all state variables. Attachment 1 also includes updated terminology and types of modeling data, such as modeling data on wind turbines and photovoltaic systems, which were not explicitly listed in the Existing MOD B Standards but are important for modeling purposes moving forward.

Additionally, Attachment 1 also includes short-circuit modeling data, consistent with the Commission's directive from FERC Order No. 890[45] and the recommendation from the SAMS Whitepaper. As stated in the SAMS Whitepaper, because short circuit analysis is required by other Reliability Standards,[46] the Existing MOD B Standards should require that neighboring entities share a sufficient level of short-circuit data to enable the studies required by those other Reliability Standards.[47] Further, as noted above, it is important to construct short circuit models to perform system protection analyses and support analysis at the seams between neighboring regions.

Because not all essential data items can be explicitly listed, particularly in light of ongoing technological developments, Attachment 1 specifically allows the Planning Coordinator or

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[44] Lack of specificity in the Existing MOD B Standards was cited in the SAMS Whitepaper as an issue, especially for dynamics models.

[45] *See* Order No. 890 at P 290.

[46] *See* FAC-002-1, Requirement R1.1.4; TPL-001-4, Requirement R2.

[47] SAMS Whitepaper at 4.

Transmission Planner to request any additional information not explicitly listed in Attachment 1 but that is necessary for modeling purposes. As industry modeling needs may change over time due to, among other things, newly developed technology, this provision allows Planning Coordinators and Transmission Planners to request the appropriate data to match their modeling needs without having to modify Attachment 1 through NERC's standards development process. For the same reason, the modeling data requirements in Attachment 1 reflect basic equipment characteristics that are independent of the specific technology used in a particular installation.

Proposed Reliability Standard MOD-032-1 also recognizes that operational disparities exist across North America, providing Planning Coordinators and Transmission Planners the flexibility to tailor their data requirements and reporting procedures to their specific circumstances and Interconnection. Requirement R1 does not prescribe all of the technical details associated with the preparation and submittal of model data because, in large part, it is dependent upon evolving industry modeling needs. In accordance with part 1.2 of Requirement R1, Planning Coordinators and Transmission Planners may specify the data format, level of detail, and case types or scenarios that are most appropriate to their needs and circumstances, so long as they are consistent with the procedures for building the Interconnection-wide cases.[48] Similarly, Attachment 1 specifies, consistent with the recommendation in the SAMS Whitepaper, that the

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[48] The entities that currently build the Interconnection-wide cases for each Interconnection have procedural manuals for developing the cases. The Eastern Interconnection Reliability Assessment Group ("ERAG"), a construct of the six Regional Entities in the Eastern Interconnection which builds the Eastern Interconnection cases, uses its Multiregional Modeling Working Group (MMWG) Procedural Manual, available at: https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Pages/default.aspx. The Western Electricity Coordinating Council ("WECC"), which builds the Western Interconnection cases, uses its Data Preparation Manual for Power Flow Base Cases and Dynamic Stability Data, available at: http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/SRWG/Shared%20Documents/Forms/AllItems.aspx. Finally, the Electric Reliability Council of Texas ("ERCOT"), which builds the ERCOT Interconnection cases uses the ERCOT Steady State Working Group Procedural Manual and the ERCOT Dynamics Working Group Procedural Manual, available at http://www.ercot.com/committees/board/tac/ros/sswg/ and http://www.ercot.com/committees/board/tac/ros/dwg/, respectively.

modeling data to be collected must be shareable on an Interconnection-wide basis so that it could be used in the Interconnection-wide cases.

Requirement R1 also does not mandate the exact reporting procedures that Planning Coordinators and Transmission Planners must use, allowing them to create efficiencies in their processes based on their particular circumstances. Requirement R1 is drafted to provide Planning Coordinators and Transmission Planners the flexibility to continue their existing practices or develop new practices so long as certain data requirements and reporting procedures are included and are consistent with the procedures for building the Interconnection-wide cases.[49]

Lastly, Requirement R1, part 1.3 mandates that the Planning Coordinator and Transmission Planners specify when they will make available their data requirements and reporting procedures to the applicable data owners. This obligation will help ensure that an entity responsible for providing such data under Requirement R2 has proper notice of the data requirements and reporting procedures.

Requirement R2 obligates applicable data owners to provide modeling data to their Planning Coordinator and Transmission Planner according to the data requirements and reporting procedures developed pursuant to Requirement R1. Requirement R2 provides:

> Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.

[49] The proposed Reliability Standard allows Planning Coordinators whose areas are interrelated to enter into agreements to establish a common data collector for their planning areas.

Requirement R2 helps ensure that data owners supply their data to support the model building process. Requirement R2 is drafted to accommodate arrangements in which the Planning Coordinator collects all the data directly or instances in which Transmission Planners serve as conduits for the collection of data, per agreement with the Planning Coordinator. The intent of the requirement is not to change established practices or mandate the specific arrangement for data collection but to reinforce and emphasize accountability for those entities that are in the best position to have and provide the necessary modeling data.

Requirement R3 provides Planning Coordinators, Transmission Planners, and the data owners the opportunity to collaboratively address any technical concerns with the data provided under Requirement R2. Requirement R3 provides:

> Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows:
>
> 3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;
>
> 3.2 Provide the response within 90 calendar days, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

As noted above, in order to maintain accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform power flow, dynamics, and short circuit studies can change, for example, as a result of newly planned transmission construction (in comparison to as-built information). Another example is load forecasts, which can change frequently. Updates to load modeling data are needed when new forecasts are developed. Requirement R3 provides a mechanism for the Planning Coordinator and Transmission Planner to ensure that the data being collected is correct and updated. It also allows them to address concerns about the usability of data, including whether the data is in the correct format and shareable on an Interconnection-wide basis. This type of feedback loop is not provided in the Existing MOD B Standards and represents a significant improvement to reliability.

Requirement R4 obligates Planning Coordinators to provide models for its planning area reflecting the data provided under Requirement R2 to the ERO (or its designee) for use in building the Interconnection-wide cases. Requirement R4 provides:

> 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.

Requirement R4 completes the data collection framework for the Interconnection-wide case building process. Once the Planning Coordinator receives all of the modeling data requested pursuant to Requirement R1, it will develop planning models for its entire planning area. These models form the basis for constructing the Interconnection-wide cases necessary to study the reliability of each Interconnection. Because NERC and the Regional Entities have the wide area view necessary to facilitate the building of the Interconnection-wide cases, it is appropriate to require Planning Coordinators to make available the model data for their planning areas to the ERO (or its designee) to support the Interconnection-wide case building process.

Currently, in collaboration with NERC, the six Regional Entities in the Eastern Interconnection, through ERAG, build the Eastern Interconnection cases, WECC builds the Western Interconnection cases, and ERCOT builds the ERCOT Interconnection cases. While ERAG and ERCOT build seasonal models on an annual basis, WECC builds models on a continuous basis throughout the year. Requirement R4 does not require any changes to those practices. The intent of the requirement is to support both existing practices and any future modifications to those practices. The requirement for Planning Coordinators to submit their models to the "ERO or its designee" supports a framework whereby NERC, in collaboration with the Regional Entities and/or any other organization, has the necessary information to build the Interconnection-wide cases.

2. <u>Proposed Reliability Standard MOD-033-1</u>

Proposed Reliability Standard MOD-033-1 is a new Reliability Standard that requires each Planning Coordinator to implement a documented process to perform model validation within its planning area. Because of the importance of models in analyzing the reliability of the Bulk-Power System, comparing the performance of power system models against actual measured power system data (i.e., model validation) is an essential procedure for measuring the accuracy of power system models and, ultimately, maintaining system security and reliability. The Existing MOD B Standards, however, did not contain any validation requirements. Consistent with Commission directives, the addition of proposed Reliability Standard MOD-033-1 will serve the important reliability goal of monitoring and improving the accuracy of the models used in power system studies.

Proposed Reliability Standard MOD-033-1 contains two requirements. Requirement R1 requires Planning Coordinators to implement a validation process for (i) comparing the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior; and (ii) comparing the performance of the Planning Coordinator's portion of the existing system in a planning dynamics model to actual system response. Because the Planning Coordinator will need actual system behavior data to perform the validations, Requirement R2 requires Reliability Coordinators and Transmission Operators to supply actual system data to any requesting Planning Coordinator for purposes of model validation. Validation of the Interconnection-wide cases is not covered by proposed Reliability

Standard MOD-033-1. As the ERO facilitates the construction of the Interconnection-wide cases, it will also facilitate the validation of those cases to help ensure they are accurate and up to date.

The following is a discussion of each requirement in proposed Reliability Standard MOD-033-1.

<u>Requirement R1</u> provides as follows:

> R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes:
>
> 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;
>
> 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 (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;
>
> 1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and
>
> 1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

As noted, implementation of these validation processes will result in more accurate power flow and dynamics models. The increased accuracy should provide for better correlation between system flows and voltages seen in power flow studies and the actual values observed by system operators. For dynamics studies, it is expected that the results of such studies will more closely match the actual responses of the power system to disturbances.

Requirement R1 focuses on the results-based outcome of developing a process for performing a validation. While it does not prescribe a specific method or procedure for the validation, it does specify common criteria that must be included in the process. The standard drafting team concluded that Planning Coordinators should have the discretion to develop processes that best suit their planning areas, so long as those processes satisfy parts 1.1 through 1.4 of Requirement R1.

Similarly, the proposed Reliability Standard does not specify numeric accuracy thresholds for what constitutes an unacceptable difference within the proposed Reliability Standard. Specifying a generally applicable accuracy threshold is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant). The standard drafting team determined that each Planning Coordinator is best suited to define what constitutes an unacceptable difference for its system(s). Requirement R1 only requires that the Planning Coordinator develop guidelines for (1) evaluating discrepancies between actual system behavior or response and the system performance indicated in the planning models, and (2) resolving any unacceptable differences.[50]

The Guidelines and Technical Basis section of the proposed Reliability Standard, however, provides guidance for Planning Coordinators in the development and implementation of their validation processes. For instance, the Guidelines and Technical Basis section states, among other things, that for the steady-state model validation required by part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible but acknowledges that other snapshots of the system should be used if deemed to be more appropriate by the Planning Coordinator. It also notes that, in performing the comparison required in part 1.1, the Planning

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50 For instance, Requirement R3 of proposed MOD-032-1 can serve as a mechanism to address any issues identified during model validation.

Coordinator should consider, among other criteria: (1) system load; (2) transmission topology and parameters; (3) voltage at major buses; and (4) flows on major transmission elements.

The dynamics model validation required under part 1.2 is limited to the Planning Coordinator's planning area, and the focus is on local events or local phenomena. The Guidelines and Technical Basis section notes that the validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of: (1) voltage oscillations at major buses, (2) system frequency (for events with frequency excursions), and (3) real and reactive power oscillations on generating units and major inter-area ties.

Because the occurrence of dynamic local events is unpredictable, part 1.2 specifies that the Planning Coordinator shall use a dynamic local event that occurs within 24 calendar months of the dynamic local event used in the last comparison. If no dynamic local event occurs within the 24 calendar months from the last dynamic local event used, however, the requirement specifies that the Planning Coordinator shall use the next dynamic local event that occurs. In all cases, the requirement mandates that the Planning Coordinator complete its comparison within 24 months of the event being used.

Requirements R2 is designed to help ensure that the Planning Coordinator has the actual system behavior data necessary to perform the validations required by Requirement R1. Requirement R2 provides:

> Each Reliability Coordinator 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.

The standard drafting team identified Reliability Coordinators and Transmission Operators as the entities that are in the best position to have this data given their role in operating the Bulk-Power System.

C. The Proposed Reliability Standards Satisfy Outstanding Commission Directives

As noted above, in Order Nos. 693 and 890, the Commission issued directives to NERC to modify certain aspects of the Existing MOD B Standards. Exhibit E of this Petition provides a list of the directives and an explanation of the standard drafting team's consideration of each directive. The following is a discussion of each of the outstanding directives.

Applicability to Planning Coordinators: As discussed above, the Commission directed NERC to modify Reliability Standards MOD-010-0 through MOD-013-1 to include the Planning Coordinator as an applicable entity.[51] Consistent with that directive, the Planning Coordinator has a central role under the proposed Reliability Standards. Proposed Reliability Standard MOD-032-1 establishes the Planning Coordinator as the entity that (1) develops the modeling data requirements and reporting procedures and (2) makes available planning models for its planning area to the ERO for use in the development of the Interconnection-wide cases. The Planning Coordinator is also tasked with validating the models for its planning area under proposed Reliability Standard MOD-033-1.

Listing Contingencies: The Commission directed NERC to modify MOD-010-0 to require the filing of all of the contingencies that are used in performing steady-state system operation and planning studies.[52] The Commission asserted that "access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own

[51] Order No. 693 at P 1155, 1162, 1184, 1199.

[52] *Id*. at P 1148.

systems, which will benefit reliability."[53] The standard drafting team did not explicitly include a requirement to file contingencies in the proposed Reliability Standards because this directive has been addressed by Reliability Standards filed after the issuance of Order No. 693. Specifically, Reliability Standard TPL-001-4, Requirements R3 and R4[54] require Planning Coordinators and Transmission Planners to identify Contingencies as part of performing the planning assessments required by that Reliability Standard. Those planning assessments must be distributed to adjacent Planning Coordinators, Transmission Planners, and to any other functional entity with a reliability need. Additionally, from an operations horizon perspective, the sharing of contingencies is covered by Reliability Standard MOD-001-1a and pending Reliability Standard MOD-001-2.

Applicability to Transmission Operators: The Commission directed NERC to include Transmission Operators as an applicable entity because Transmission Operators are usually responsible for compiling the operational contingency lists for both normal and emergency operation.[55] Because the identification of contingencies is addressed by other reliability standards, as discussed above, the standard drafting team did not include Transmission Operators as applicable entities for proposed Reliability Standards MOD-032-1 and MOD-033-1.

List of Faults and Disturbances: The Commission directed NERC to modify MOD-012-0 by (1) adding a new requirement to provide a list of the faults and disturbances used in performing dynamics studies for system operation and planning[56] and (2) require the Transmission Planner to provide the fault and disturbance lists.[57] The standard drafting team did not explicitly include a

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53 *Id*.

54 Reliability Standard TPL-001-4 was approved by the Commission on October 17, 2013 and will go into effect beginning on January 1, 2015. *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013).

55 Order No. 693 at P 1154.

56 *Id*. at P 1178.

57 *Id*. at P 1183.

requirement to list faults and disturbances in the proposed Reliability Standards because this directive has been addressed by Reliability Standard TPL-001-4. As part of performing the planning assessments required by that Reliability Standard, Planning Coordinators and Transmission Planners will identify the faults and disturbances used in performing dynamics studies for system operation and planning. Further, as noted above, those planning assessments must be distributed to adjacent Planning Coordinators, Transmission Planners, and to any other functional entity with a reliability need. Accordingly, the Commission's concern with respect to transparency has been addressed by Reliability Standard TPL-001-4 and need not be duplicated in the proposed Reliability Standards.

Use of Estimates and Comparison of Dynamics Models to Actual Disturbance Data: The Commission directed NERC to modify MOD-013-1 to permit entities to estimate dynamics data if they are unable to obtain unit specific data but require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.[58] Requirement R3 of proposed Reliability Standard MOD-032-1 addresses this directive by providing a mechanism to obtain more accurate information in cases where the initial data provided has technical or accuracy concerns. Should an entity estimate dynamics data because they were unable to obtain unit specific data, the Planning Coordinator and Transmission Planner may use Requirement R3 to verify the accuracy of the estimates and request additional data as needed. Furthermore, proposed Reliability Standard MOD-033-1 requires comparison of actual disturbance data to verify the accuracy of dynamics models.

Model Validation: The Commission directed NERC to modify MOD-014-0 and MOD-015-0.1 to (1) include a requirement that the models be validated against actual system responses,

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[58] Order No. 693 at P 1197. *See also* Order No. 693-A at P 131

and (2) require 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.[59] Proposed Reliability Standard MOD-033-1 addresses these directives by adding a validation process requirement that is (1) aimed specifically at ensuring that models are validated against actual system responses and (2) that requires validation through simulation to ensure that the discrepancy between actual system performance and the model is acceptable (i.e., the discrepancy does not exceed the point where conclusions drawn by the Planning Coordinator based on output from the model would be inconsistent with operator action based on actual system response).

Updating and Benchmarking Models: In Order No. 890, the Commission directed public utilities, working through NERC, to modify Reliability Standards MOD-010 through MOD-025 to "incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date."[60] The Commission stated that "[t]his means that the models should be updated and benchmarked to actual events."[61] The concept that models should be updated and benchmarked is addressed by the proposed Reliability Standards. Proposed Reliability Standard MOD-033-1 requires entities to validate models by verifying that system behavior predicted by the models acceptably matches actual system response. Further, proposed Reliability Standard MOD-032-1, Requirement R3 provides a mechanism to update modeling data that may have technical issues.

Additionally, proposed Reliability Standard MOD-032-1 covers short circuit data and transient and dynamic stability simulation data by requiring that those items be provided to

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59 Order No. 693 at PP 1210, 1211, 1220.

60 Order No. 890 at P 290.

61 *Id*.

Planning Coordinators and Transmission Planners. The standard drafting team concluded that the portion of the directive related to contingency, subsystem, and monitoring files is addressed by TPL-001-4, Requirements R3 and R4.

D. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standards include VRFs and VSLs, which provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. Exhibit F provides a detailed review of the VRFs, the VSLs, and an analysis of how the VRFs and VSLs were determined using NERC and Commission guidelines.

The proposed Reliability Standards also include measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[62]

V. <u>EFFECTIVE DATES</u>

As described in the Implementation Plan, attached hereto as Exhibit B, NERC respectfully requests that the Commission approve the proposed Reliability Standards effective as follows:

- For Requirement R1 of proposed Reliability Standard MOD-032-1, NERC requests an effective date of the first day of the first calendar quarter that is 12 months after the date that the standard is approved by the Commission.
- For Requirements R2, R3 and R4 of proposed Reliability Standard MOD-032-1, NERC requests an effective date of the first day of the first calendar quarter that is 24 months after the date that the standard is approved by the Commission.

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[62] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

- For proposed Reliability Standard MOD-033-1, NERC requests an effective date of the first day of the first calendar quarter that is 36 months after the date that the standard is approved by the Commission.

The effective dates for the proposed Reliability Standards were developed to maximize opportunities for coordination between entities. These implementation periods will allow for the development of sound data requirements and reporting procedures, accurate submissions from data owners, and effective validation processes. The standard drafting team determined that staggering the effective dates for proposed Reliability Standard MOD-032-1 in this manner was appropriate given the timeframes for complying with the various requirements. Compliance with Requirements R2-R4 is dependent on the data requirements and reporting procedures developed by Planning Coordinators and Transmission Planners in accordance with Requirement R1. Further, to ensure accurate validation of the models, a 36-month implementation period is appropriate as it should provide sufficient time for Planning Coordinators to develop rigorous procedures for validation after entities have had time to comply with the requirements in proposed MOD-032-1.

NERC also respectfully requests that the Commission approve the retirement of MOD-010-0 and MOD-012-0 and withdrawal of MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 effective on midnight of the day immediately prior to the effective date for Requirement R2 of MOD-032-1. The proposed retirement date is appropriate because MOD-010-0 and MOD-012-0, the only Existing MOD B Standards approved by FERC, map to Requirement R2 of MOD-032-1, as described in Exhibit D hereto.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed Reliability Standards and associated elements included in Exhibit A**,** effective as proposed herein;
- approve the Implementation Plan included in Exhibit B; and
- approve the retirement of the currently effective Reliability Standards MOD-010-0 and MOD-012-0, and the withdrawal of pending Reliability Standards MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, effective as proposed herein.

Respectfully submitted,

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Date: February 25, 2014

Exhibit A

Proposed Reliability Standards

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-1**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

“Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

			steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 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* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. 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 entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. 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).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:

a. add requirement identifying who provides and who receives data;
b. identify acceptability;
c. standard format;
d. how to deal with new technologies (user written models if no standard model exists); and
e. shareability.

4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**

2. **Number: MOD-033-1**

3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

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;

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 (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see "Procedures for Validation of Powerflow and Dynamics Cases" produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies "once every 24 calendar months," entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator's planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a “month 23” dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.

Exhibit B

Implementation Plan

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

October 7, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards
MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirement R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements

MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Exhibit C

Order No. 672 Criteria

Exhibit C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

Proposed Reliability Standards MOD-032-1 and MOD-033-1 are designed to achieve the specific reliability goal of maintaining the reliable operation of the Bulk Power Supply by setting parameters for the acquisition and analysis of modeling data necessary for the development of planning models and Interconnection-wide cases. Such models provide the basis for nearly all power system studies used to assess the reliability of the Bulk-Power System.

The proposed Reliability Standards also satisfy outstanding Commission directives from Order Nos. 693 and 890.

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1 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

2 Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply. Proposed Reliability Standard MOD-032-1 applies to Balancing Authorities, Generator Owners, Load Serving Entities, Planning Authorities and Planning Coordinators, Resource Planners, Transmission Owners, Transmission Planners, and Transmission Service Providers. Proposed Reliability Standard MOD-033-1 applies to Planning Authorities and Planning Coordinators, Reliability Coordinators, and Transmission Operators. The actions that each entity must take to comply with the proposed Reliability Standards are clearly articulated.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. The assignments of the severity levels for the VSLs are consistent with the corresponding Requirements and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, and support uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences.

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

4. **A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.**[5]

The proposed Reliability Standard contains Measures that support the Requirements by clearly identifying what is required and how the Requirement will be enforced. The proposed Measures for proposed Reliability Standard MOD-032-1 are as follows:

> **M1.** Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirement and reporting procedures specified in Requirement R1.
>
> **M2.** Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that is has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.
>
> **M3.** Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that is has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerned with the data submitted.
>
> **M4.** Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that is has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

The proposed Measures for proposed Reliability Standard MOD-033-1 are as follows:

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[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

> **M1.** Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.
>
> **M2.** Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

These Measures help provide clarity regarding how the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. **Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]**

The proposed Reliability Standards achieve the reliability goals effectively and efficiently. The proposed Reliability Standards consolidate several current Reliability Standards, streamlining and updating the processes for the collection of modeling data. The collection of accurate modeling development supports the development of accurate Interconnection-wide cases, which are necessary for studying the reliability of the Bulk Power System.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.,* cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for**

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[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard represents a significant improvement over existing Reliability Standards as described herein. In addition to satisfying Commission directives, the Reliability Standards as proposed include a comprehensive process for collecting the information necessary to develop accurate Interconnection-wide cases.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[8]

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model. The proposed Reliability Standards are drafted to accommodate the various practices across the continent.

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7 Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

8 Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

Proposed Reliability Standards MOD-032-1 and MOD-033-1 have no undue negative effect on competition. The proposed Reliability Standards require the same performance by each of the applicable Functional Entities in requiring the collection of modeling data. The proposed Reliability Standards do not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the proposed Reliability Standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as Exhibit B.

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[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

10. **The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.**[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. Exhibit G includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standard. These processes included, among other things, multiple comment periods and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public. The initial and final ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. **NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.**[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

12. **Proposed Reliability Standards must consider any other appropriate factors.**[13]

No other factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[11] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Mapping Document

Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-012-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-013-1, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R3	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, it provides a mechanism to obtain more accurate information and data in cases where the initial data provided may have technical or accuracy concerns, and it meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" In those cases, additional detail regarding the data may be necessary.
NEW	MOD-032-1, R4	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective Interconnection-wide case(s).
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

Exhibit E

Consideration of Directives

Consideration of Issues and Directives

Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R3 provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by Project 2012-05 ATC Revisions (MOD A).

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific “at a minimum” data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as	FERC Order No. 693	See the response to Paragraph 1155.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	See the response to Paragraph 1148.
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission planner to provide fault and disturbance lists.		
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" This is being addressed by MOD-032, Requirement R3, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement R1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be	FERC Order No. 693	See response to paragraph 1210.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
validated against actual system responses.		

Exhibit F

Analysis Violation Risk Factors and Violation Security Levels

Project 2010-03 - Modeling Data

VRF and VSL Justifications

The following table provides analysis and justification for each VRF and VSL assigned in MOD-032-1 and MOD-033-1.

VRF and VSL Justifications – MOD-032-1, Requirement R1	
Proposed VRF	**LOWER**
NERC VRF Discussion	The purpose of this requirement is to ensure that the data requirements and reporting procedures established by planning coordinators meet minimum criteria. It is a requirement in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the bulk electric system.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for creation of data requirements and reporting procedures to support data used in Interconnection-wide power flow and dynamics cases. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Lower VRF is consistent with the risk impact of a violation.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement maps from MOD-011-0 and MOD-013-0, which were not approved by FERC, which has a VRF of High for the main requirement and Medium for the requirement parts. Requirement R1 acts in concert with its corollary requirement, Requirement R2, which requires data owners to submit the required data, which has a VRF of Medium, and together the VRFs are consistent with previous versions.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.

FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R2	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	The purpose of this requirement is to ensure that data owners subject to the standard submit data according to the data requirements and reporting procedures established by Planning Coordinators under Requirement R1. Not providing the data could directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for submission of data according to data requirements and reporting procedures to support Interconnection-wide power flow and dynamics cases. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Medium VRF is consistent with the risk impact of a violation, especially in light of the blackout recommendations.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement maps from MOD-010 and MOD-012, which have VRFs of Medium; therefore, the VRF is consistent with previous versions.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than

less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit

			modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R3	
Proposed VRF	**LOWER**
NERC VRF Discussion	This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. As a feedback loop for increasing accuracy of data, violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system, and a Lower VRF is appropriate.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement provides a feedback loop for certain circumstances, and the VRF is only applied at the requirement level and the Requirement Parts are treated equally. The assigned VRF is consistent with the risk impact of a violation across the standard.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This is a new requirement and is commensurate in risk with Requirement R1. Both requirements have the same VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	Coordinator or Transmission Planner).		

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R4	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). Information for use in the planning models is important, and a violation of this requirement could affect reliability, but a violation would not likely lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Requirement R4 specifies actions to ensure that data provided under the standard is available for use in the Interconnection-wide case(s), and, much like the importance of entities providing the data under Requirement R2, a VRF of Medium is appropriate.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces MOD-014 and MOD-015, and a Medium VRF is consistent with those standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-033-1, Requirement R1	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	This requirement requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response. Accuracy of data used in the planning models may be affected. A violation of this requirement could affect reliability, but a violation would not likely lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement specifies that Planning Coordinators must implement a data validation process. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Medium VRF is consistent with the risk impact of a violation.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: N/A. There are no other NERC Reliability Standards that address similar reliability goals
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar months (or the next dynamic local event in cases where there is more than 24 months between events).

did perform the simulation within 28 calendar months.	did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	than or equal to 36 calendar months.	

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-033-1, Requirement R2			
Proposed VRF	**LOWER**		
NERC VRF Discussion	The purpose of this requirement is to ensure that actual system behavior data is available for Planning Coordinators for use in validation under Requirement R1. The information is in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the bulk electric system.		
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.		
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for certain entities to provide certain data to Planning Coordinators in support of the validations required of the Planning Coordinators under Requirement R1. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Lower VRF is consistent with the risk impact of a violation.		
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: N/A. There are no other NERC Reliability Standards that address similar reliability goals		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not

provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days; OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

Exhibit G

Summary of Development History and Record of Development

Summary of Development History

The development record for proposed Reliability Standards MOD-032-1 and MOD-033-1 are summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT"). For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the team members is included in Exhibit H.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was submitted to the Standards Committee ("SC") in December 2012 and accepted by the SC in July 2013.

B. First Posting

Proposed Reliability Standards MOD-032-1 and MOD-033-1 were posted for a 45-day public comment period from July 22, 2013 through September 4, 2013. There were 72 sets of responses, including comments from approximately 201 individuals from approximately 91 companies representing all of the 10 industry segments. The proposed Reliability Standards received a quorum of 82.29% and an approval 41.24%.

The standard drafting team considered stakeholder regarding proposed Reliability Standard MOD-032-1 and made the following observations and modifications based on those comments:

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

- **Short Circuit Data**
    - Commenters questioned if steady-state, dynamics, and short circuit data should be in a separate standard and if short circuit data should even be part of any NERC standard data request.
        - The SDT considered the comments from stakeholders and the majority preference was to combine them as it creates fewer requirements.
        - Regarding the need to include short circuit data, the directive from FERC Order No. 890, paragraph 290, specifically requires inclusion of short circuit data.
    - The SDT also offered the following observation:
        - System protection is often perceived to be the sole use for short circuit data. However, short circuit data is also used in conjunction with power flow and dynamics applications, for example, to adaptively calculate unbalanced fault shunt admittance for prior outages and sequential clearing in dynamic simulations, particularly where regional stability is or could be impacted.
- **Regional Reliability Organizations (RRO) Applicability**
    - Commenters expressed concern over Regional Reliability Organizations ("RROs") not controlling the data collection procedure as in the current MOD-010 through MOD-015 standards.
    - The SDT noted that the standard does not preclude a Regional Entity's (RE) involvement in the data collection; however, the designation RRO is not in the NERC functional model, and NERC Reliability Standards' applicability is based on those functions. Therefore, NERC cannot require the "RRO" to develop data requirements and reporting procedures.
- **Registration Concerns**
    - Commenters raised registration concerns.
        - The SDT agreed with commenters that for this standard to work effectively, the PC will need to know all registered entities (TOs, GOs, TPs, Distribution Providers (DPs), Load Serving Entities (LSEs), Transmission Service Providers (TSPs), and RPs) within its purview, and vice versa (entities need to know who their PC is).
        - The SDT noted these comments and guidance at the end of the standard addresses some of these issues.
- **Requirement R1**
    - Commenters raised concern with the PC-developed data collection procedures. Specific concerns were data collection consistency and whether a PC could require data that is not needed for reliability.
        - The SDT added clarification to Requirement R1 that PCs must create their data requirements and reporting procedures jointly with TPs, and the

    - requirement is more specifically linked to support Interconnection-wide modeling to address inconsistency concerns.
    - In addition, the SDT noted that the data in Attachment 1 is separate from the other criteria and no longer "at a minimum."
  - Commenters questioned Requirement R1, parts 1.1 through 1.6, asking why this criteria was included in the requirement and not in an attachment.
    - The SDT noted that Attachment 1 is part of Requirement 1, and that it specifies the data that must be provided. The rest of the criteria inform details that must be included in the data requirements and reporting procedures relative to that data.
- **Requirement R2**
  - Commenters suggested distribution to data owners upon any modification instead of providing to data owners upon request.
    - The SDT discussed that the requirement clarifies the responsibility and obligation of the PC to distribute the procedures upon request and is therefore not purely administrative.
  - Commenters suggested MOD-032-1 Requirement R2 falls under the Paragraph 81 criteria. The Paragraph 81 criteria addresses "requirements that obligate responsible entities to report to a Regional Entity, NERC, or another party or entity "on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact." (Emphasis added).
    - The SDT did not agree that Paragraph 81 is invoked since the submission of data for use in the planning models does constitute "promoting the reliable operation of the BES" and that there would be a "reliability impact" if data is not submitted for the planning models since planning the transmission system for future growth is necessary to ensure reliability.
- **Requirement R3**
  - Commenters questioned why the TP and PC are listed to receive data.
    - The SDT noted that while the PC and TP are listed, it also states "according to the data requirements and reporting procedures developed by its Planning Coordinator in Requirement R1," so this could be further specified in the procedure defined in Requirement R1.
- **Requirement R4**
  - Commenters raised concerns regarding the Requirement R4 feedback loop.
    - After much discussion, the SDT kept requirement R4 and made modifications in response to:
      - Requirement R4, Part 4.2 (related to user-defined models) was removed, though the concept was added to Attachment 1 under the dynamics data heading;

    - Old Part 4.3 (now Part 3.2) was changed from 30 days to 90 days; and
    - Requirement R5 (now Requirement R4) was modified to state that the PC submits models "reflecting" the data it receives to support creation of Interconnection-wide cases to address the concern about whether the PC is obligated to use data it knows may be inaccurate (i.e., the PC can modify the data upon submission to reflect a more accurate representation if necessary).

- **Requirement R5**
  - Commenters expressed concerns about the Interconnection-wide case building process and Requirement R5. Some Commenters suggested using section 1600 data request to collect data for interconnection model building.
    - The SDT pointed out that this standard is about specifying the relationship of obligations between and among different functional entities, not about providing data to the ERO.
  - Commenters expressed concerns that even though the PC can create Planning Horizon models for its region, they cannot build a 'standalone' model to perform studies without the coordinated efforts of external entities within the planning horizon (i.e. Interconnection models). Similarly, some comments asked who is responsible for building the Interconnection-wide cases under the standard.
    - The SDT pointed out that while the standard does not prescribe how the Interconnection-wide case is built, the standard is limited to directing the PC to provide the information to the entity that does create the model (the standard is not a standard to create the Interconnection-wide case, it is a standard outlining obligations among other functions to support collection of data for use in the Interconnection-wide case).
  - Commenters also raised concern that PCs need to collaborate to build Interconnection-wide cases.
    - The SDT agreed and notes that the framework does not prohibit such collaboration.
  - Several commenters raised concern that Requirement R5 required each PC to submit data to the ERO or its designee to support creation of the Interconnection-wide cases, and that the PCs have no obligation to collect data on the same schedule and no obligation to build the same set of models.
    - The SDT clarified that Requirement R1 procedures support Interconnection-wide case building, and the PC obligation under Requirement R5 (now Requirement R4) would inform development of the data requirements and reporting procedures.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard MOD-033-1 and made the following observations and modifications based on those comments:

- The SDT assured commenters that MOD-033-1 is focused on validation of "planning models." The planning model should be modified to be as consistent as possible with a real-time snap shot of topology, load, and generation pattern. The SDT made changes to MOD-033-1 to further clarify that the focus is on planning models in the purpose of the standard and in Requirement R1 by specifying it is the "planning" models.
- Commenters questioned the validation timelines in MOD-033-1, stressing that 24 months was too frequent an interval to simulate a "local dynamic event". In addition, commenters indicated that the set-up of the simulation itself and completion of the simulation could take up to 18 months and the timelines in MOD-033-1 would result in a continuous amount of additional work necessitating additional staff.
    - The SDT kept the 24 month requirement but removed the requirement to complete the simulation within 12 months of an event if an event had not occurred within the last 24 months.
    - The SDT clarified that the "local dynamic event" does not have to be a severe event requiring a large amount of set-up, but could be much smaller events that if done frequently over time would validate portions of the model in each 24 month period.
    - The SDT also provided greater explanation of "dynamic local event" in the background section of the standard.
    - In response to concern that validation every two years will be a large engineering effort, the SDT noted that the requirements are focused on planning area validation, and it leaves a lot of decisions regarding validation to the discretion of the PC.
- Commenters asked for clarification of what constitutes a "dynamic local event." The SDT stated that the determination of "dynamic local event" is expected to be part of the validation process implemented by the PC.
    - In the rationale for Requirement R1 in MOD-033-1, the "simulation of significant system disturbances and comparing the simulation results with the actual event results" is specified, but the rationale further states that "the details of 'how'" is not specified and is "best left to guidance rather than standard requirements."
    - The Application Guidelines further state that dynamics model validation is limited to the PC area and the emphasis is on local events or phenomena, not the entire Interconnection, and the SDT added more explanation to the background of MOD-033-1 about a dynamic local event.
- Commenters expressed concerns regarding the expectations for accuracy in MOD-033-1.

    - The SDT modified Requirement R1 to state that the PC will implement a process to conduct the model validation that includes guidelines to determine unacceptable differences and guidelines to resolve those differences.
- Commenters were concerned about which models to use in the validation. They stated that the RC Operations model should be used instead of the Near-Term planning cases that represented conditions one to five years into the future.
    - The SDT emphasized that the planning cases should be used because the very point of MOD-033-1 is to make sure the planning cases, modified to represent a real-time condition, exhibit the same or similar performance as the operations models.

C. Second Posting

Proposed Reliability Standards MOD-032-1 and MOD-033-1 were posted for a 45-day public comment period from October 7, 2013 through November 20, 2013. There were 54 sets of responses, including comments from approximately 163 individuals from approximately 105 companies representing 9 of the 10 industry segments. Proposed Reliability Standard MOD-032-1 received a quorum of 79.05% and an approval of 73.46%. Proposed Reliability Standard MOD-033-1 received a quorum of 79.84% and an approval of 69.42%.

The standard drafting team considered stakeholder comments on the proposed Reliability Standard MOD-032-1. Commenters expressed concern with the change in Requirement R1 for Planning Coordinators and Transmission Planners to "jointly develop" steady-state, dynamics, and short-circuit modeling data requirements and reporting procedures for the PC's planning area. The specific concern was compliance related. The SDT examined this issue and determined no change was necessary as the proposed standard does not specify how entities must jointly develop the data requirements and reporting procedure and, in addition, provides for several alternatives to satisfy the Requirement.

The standard drafting team considered stakeholder to the proposed Reliability Standard MOD-033-1. A commenter stated that for Requirement R1, part 1.2, there is no specific timeframe given in which the comparison should be completed after the event if the event does not occur within the first 24 months, which could lead to concerns that an auditor could expect it to be done more quickly than is possible. To address this concerns, the SDT rephrased R1 part 1.2 to clarify the intent of the Requirement to ensure it is clear that the PC will not face a timing scenario that makes it impossible to comply. Proposed Reliability Standard was subject to an additional ballot because of this change.

D. Third Posting

Proposed Reliability Standard MOD-033-1 was posted for a 45-day public comment period from December 6, 2013 through January 22, 2014. There were 32 sets of responses, including comments from approximately 106 individuals from approximately 54 companies representing 9 of the 10 industry segments. Proposed Reliability Standard MOD-033-1 received a quorum of 76.92% and an approval of 81.41%.

The standard drafting team considered stakeholder comments and made no revisions to the proposed Reliability Standard MOD-033-1 based on those comments.

E. Final Ballots

Proposed Reliability Standard MOD-032-1 was posted for a 10-day final ballot period from December 6, 2013 through December 16, 2013. The proposed Reliability Standard received a quorum of 87.53% and an approval rating of 77.49%.

Proposed Reliability Standard MOD-033-1 was posted for a 10-day final ballot period from January 27, 2014 through February 5, 2014. The proposed Reliability Standard received a quorum of 82.49% and an approval rating of 82.45%.

F. Board of Trustees Approval

Proposed Reliability Standards MOD-032-1 and MOD-03301 were approved by the NERC Board of Trustees on February 6, 2014.

Complete Record of Development

Project 2010-03 Modeling Data (MOD B)

Related Files

Status:
MOD-032-1 and MOD-033-1 were adopted by the NERC Board of Trustees on February 6, 2014 and will be submitted to the appropriate regulatory authority.

Background:
NERC Reliability Standards MOD-010 through MOD-015 address modeling data requirements that support the mathematical model representations of transmission, generation, and load that are the foundation of virtually all power system studies. Only two of those standards were approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Order No. 693. Four of them were neither approved nor remanded, and they remain in a pending status.

NERC initiated an informal development process ("MOD B") to address the remaining directives related to the existing standards from FERC Order Nos. 890 and 693, and the Project 2010-03 Modeling Data Standard Drafting Team was formed following that informal development process. Two new reliability standards are proposed to replace MOD-010 through MOD-015. The proposal includes a combined modeling data standard, MOD-032-1, and a new validation standard to address directives related to validation, MOD-033-1.

The proposed standards are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires a minimum level of data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection model building process in their Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented data validation process for its planning area.

If you have any questions, please contact sarcomm@nerc.net.

Draft	Action	Dates	Results	Consideration of Comments
MOD-033-1 Model Validation Clean **(71)** | Redline **(72)** Implementation Plan **(73)** Supporting Materials: Consideration of Issues and Directives **(74)** Mapping Document **(75)**	Final Ballot Info>> **(79)** Vote>>	01/27/14 - 02/05/14	Summary>> **(80)** Ballot Results>> **(81)**	

Compliance Input (76) Draft Reliability Standard Audit Worksheet (77) VRF/VSL Justifications (78)				
MOD-032-1 Modeling Data Clean (60)| Redline (61) Implementation Plan (62) Supporting Materials: Consideration of Issues and Directives (63) Mapping Document (64) Compliance Input (65) Draft Reliability Standard Audit Worksheet (66) VRF/VSL Justifications (67)	Final Ballot Info>> (68) Vote>> (Closed)	12/6/13-12/16/13	Summary>> (69) Ballot Results>> (70)	
MOD-033-1 Model Validation Clean (44)| Redline (45) Implementation Plan (46) Supporting Materials: Unofficial Comment Form (Word) (47) Consideration of Issues and Directives (48)	Additional Ballot and Non-Binding Poll Updated Info (52) Info (53) Vote>> (Extended and additional day) (Closed)	1/10/14 - 1/22/14	Summary (55) Ballot Results (56) Non-Binding Poll Results (57)	
	Comment Period	12/6/13 - 1/22/14	Comments Received (58)	Consideration of Comments (59)

Mapping Document (49) Compliance Input (50) Draft Reliability Standard Audit Worksheet (51)	Info (54) Submit Comments>> (Closed)			
MOD-032-1 Modeling Data Clean (20)| Redline (21) MOD-033-1 Model Validation Clean(22) | Redline (23) Implementation Plan Clean (24) |Redline (25) Supporting Materials: Unofficial Comment Form (Word) (26) Compliance Input (27) Consideration of Issues and Directives Clean (28) | Redline (29) Mapping Document Clean (30)| Redline (31) Draft Reliability Standard Audit Worksheets MOD-032-1 (32) MOD-033-1(33)	Additional Ballot and Non-binding Poll Updated Info (34) Info (35) Vote>> (Closed)	11/08/13 - 11/20/13	Summary> (37) Ballot Results: MOD-032-1 (38) MOD-033-1 (39) Non-Binding Poll Results: MOD-032-1 (40) MOD-033-1 (41)	Consideration of Comments>> (43)
	Comment Period Info>> (36) Submit Comments>> (Closed)	10/07/13 - 11/20/13	Comments Received (42)	
Draft Standards MOD-032-1 (1) MOD-033-1 (2) Implementation Plan (3)	MOD-032-1 and MOD-033-1 Ballot and Non-	08/26/13 - 09/04/13 07/22/13 - 09/04/13	Summary (15) Ballot Results (16) Non-binding	

Standard Authorization Request **(4)** **Supporting Materials:** Unofficial Comment Form (Word) **(5)** Informal Development History **(6)** Consideration of Issues and Directives **(7)** Mapping Document **(8)** Compliance Input **(9)** Proposed Timeline for the Formal Development **(10)**	binding Poll Updated Info>>**(11)** Vote>> (Closed)		Poll Results **(17)** Comments Received **(18)**	
	Comment Period Info>> **(12)** Submit Comments>> (Closed)	09/09/13		Consideration of Comments >>**(19)**
	Join Ballot Pool>> (Closed)	07/22/13 - 08/20/13		
	Info>> **(13)** Submit Nomination>> Unofficial Nomination Form>> **(14)** (Closed)	07/24/13 - 08/02/13		

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (Dates of posting TBD).

Description of Current Draft

This is the first posting of this standard for a 45-day formal comment period and initial ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-033-1 seek to address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Initial Ballot	July 2013
Recirculation ballot	September 2013
BOT adoption	November 2013

Effective Dates

In those jurisdictions where regulatory approval is required, Requirements R1 and R2 shall become effective on the first day of the fourth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the fourth calendar quarter after Board of Trustees approval, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after Board of Trustees approval.

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**
2. **Number: MOD-032-1**
3. **Purpose: To establish consistent modeling data requirements and reporting procedures to support analysis of the reliability of the interconnected transmission system.**
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authorities

   4.1.2 Generator Owners

   4.1.3 Load Serving Entity

   4.1.4 Planning Coordinators

   4.1.5 Resource Planners

   4.1.6 Transmission Owners

   4.1.7 Transmission Planners

   4.1.8 Transmission Service Providers

5. **Background:**

   MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires a minimum level of data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the interconnection model building process in their interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

   The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short-circuit data also required to perform short-circuit studies. The addition of short-circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In attempting to develop a performance-based standard that would address the data requirements and reporting procedures for model data, the MOD B informal standard development group found that it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator as the developer of technical model data requirements and reporting procedures to be followed by the data owners in its planning area. The inclusion of the Transmission Planners in the applicability is intended to ensure that the Transmission Planners are able to participate in the development of the data requirements and reporting procedures.

The requirement parts of Requirement R1 list the minimum set of items that must be included in the data requirements and reporting procedures developed by the Planning Coordinator.

Coordination between Planning Coordinators in the development of these requirements and reporting procedures is necessary in order to facilitate development of interconnection-wide models. While Requirement R1 does not require this coordination, Requirement R5 includes a requirement for the Planning Coordinators to submit model data for interconnection model building in the format specified by the ERO or its designee. It would likely be most efficient for Planning Coordinators to fashion their data requirements and reporting procedures with the interconnection-wide common format in mind.

(Rationale continued on next page)

Rationale for R1: Continued

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf.

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.

These suggested improvements in the proposed approach are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, and the collection of short-circuit data is also consistent with FERC Order 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

Data submitted to effectively model a transmission system is typically on a per-element(s) basis as the transmission system evolves. Therefore, the submittal of data, and the checking of data, is much simplified by submitting all parameters describing a specific element simultaneously, thus reducing the possibility for error in the data. Typically all data in some shape or form consists of steady-state, dynamic, and short-circuit related data and is used for these types of analysis.

The approach for the collection of data is done using an attachment approach. The attachment specifically lists the Responsible Entities that are required to provide each type of data and the data that is required. This attachment takes an "at-a-minimum" approach for the collection of data needed for the construction of the models specific to seasonal cases and specific cases and scenario and for an interconnection wide model that is not software specific. It includes data for steady-state, dynamics and short circuit. It clearly holds the Responsible Entities that have the data accountable for providing data.

Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

R1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area, including: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Specification of the required data that includes, at a minimum, the data listed in Attachment 1;

1.2. Specification of the data format;

1.3. Specification that the data must be shareable on an interconnection-basis to support use in the interconnection models;

1.4. Specification of the level of detail to which equipment shall be modeled;

1.5. Specification of the case types or scenarios to be modeled; and

1.6. A schedule for submission or confirmation of data at least once every 13 calendar months.

M1. Examples of evidence include, but are not limited to, dated documentation or records that the required modeling data requirements and reporting procedures meet the specifications in Requirement R1.

Rationale for R2:

An entity responsible for providing data under Requirement R3 has an obligation to submit data according to the data requirements and reporting procedures in its planning area developed under Requirement R1, and there may be cases, such as change of ownership, etc., that the submitting entity would need to request a copy of the data requirements and reporting procedures from its Planning Coordinator. This requirement ensures that the data requirements and reporting procedures developed under Requirement R1 by each Planning Coordinator are made available to an entity responsible for providing such data under Requirement R3.

R2. Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has distributed the requested data requirements and reporting procedures within 30 days of receiving a written request in accordance with Requirement R2; or a statement by the Planning Coordinator that it has not received a request for its data requirements and reporting procedures.

Rationale for R3:

The approach in this requirement to submit data to the Planning Coordinator satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that “the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.”

It also accounts for areas where a BA may have more than one PC. It does not create a requirement for the PC or TP, as entities receiving data. It does, however, allow for instances where a TP may serve only as a conduit for the collection of data on behalf of functional entities if all parties mutually agree. The Responsible Entity required to supply the data in those cases is still accountable for the obligation to provide the data. In those instances, the intent of the requirement is not to change those established processes, but to reinforce and emphasize accountability for data provided by those entities that are in the best position to have correct data.

R3. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Examples of evidence include, but are not limited to, dated documentation or records of submission by a registered entity of the required data (to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Rationale for R4: In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform power flow, dynamics, and short-circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the PC and TP (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the PC or TP identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

R4. Upon delivery of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R3, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

4.2. If requested by the notifying Planning Coordinator or Transmission Planner, provide additional dynamics data describing the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables; and

4.3. Provide the response within 30 calendar days, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M4. Examples of evidence include, but are not limited to: dated records of a written request from the Transmission Planner or Planning Coordinator notifying a Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider regarding technical concerns, and additional evidence demonstrating the response to the request by the notified registered entity meets the specifications of Requirement R4; or a statement by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider that it has not received notification regarding technical concerns with the data submitted.

Rationale for R5: This requirement will replace MOD-014 and MOD-015

It recognizes the differences among interconnections in model building processes, but creates an obligation for PCs to provide the data in a manner that accounts for those differences.

The requirement creates a clear expectation that PCs will provide data that they collect under Requirement R3 in support of their respective interconnection models. While different entities in each of the three interconnections create the interconnection models, the requirement to submit the data to the “ERO or its designee” supports a framework whereby NERC, in collaboration with other organizations, can designate the appropriate organizations in each interconnection to build the interconnection-specific model. It does not prescribe a specific group or process to build the larger Interconnection models, but only requires the PCs to submit data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, “industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*” (Emphasis added).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection models, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection models, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection models. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the “designee” for each interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to provide the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection models.

R5. Each Planning Coordinator must submit the data provided to it under Requirement R3 to the ERO or its designee to support creation of the interconnection model(s) that includes the Planning Coordinator’s planning area as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. In the format and according to the schedule specified by the ERO or its designee; and

5.2. Include documentation and reasons for data modifications, if any.

M5. Examples of evidence may include, but are not limited to, dated documentation or records indicating data submission from the Planning Coordinator to the ERO or its designee according to Requirement R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% or less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% or less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1 OR The Planning Coordinator developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Planning Coordinator failed to	The Planning Coordinator failed to	The Planning Coordinator failed to	The Planning Coordinator failed to

			provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them within 45 calendar days.	provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them within greater than 45 calendar days but less than or equal to 60 calendar days.	provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them within greater than 60 calendar days but less than or equal to 75 calendar days.	provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request or did provide in greater than 75 calendar days.
R3	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator

			Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service	Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or	Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or	Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning

			Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

R4	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 30 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 45 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 30 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 45 calendar days but less than or equal to 60 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 30 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 60 calendar days but less than or equal to 75 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 30 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider did provide a written response to its

				longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 but not within greater than 75 calendar days (or within greater than 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R5	**Long-term Planning**	**Medium**	The Planning Coordinator submitted the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee; OR The Planning Coordinator failed to provide the required	The Planning Coordinator submitted the required data to the ERO or its designee but failed to provide greater than 25% or less than or equal to 50% of the required data in the format specified by the ERO or its designee; OR The Planning Coordinator failed to	The Planning Coordinator submitted the required data to the ERO or its designee but failed to provide greater than 50% or less than or equal to 75% of the required data in the format specified by the ERO or its designee; OR The Planning Coordinator failed to	The Planning Coordinator submitted the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee; OR The Planning Coordinator failed to provide the required data according to the

			data according to the schedule specified by the ERO or its designee but did provide the data within 15 calendar days after the specified date; OR The Planning Coordinator submitted the required data to the ERO or its designee but failed to include documentation and reasons for any data modifications.	provide the required data according to the schedule specified by the ERO or its designee but did provide the data in greater than 15 calendar days but less than or equal to 30 calendar days after the specified date.	provide the required data according to the schedule specified by the ERO or its designee but did provide the data in greater than 30 calendar days but less than or equal to 45 calendar days after the specified date.	schedule specified by the ERO or its designee and did not provide the data within 45 calendar days after the specified date.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

"At a minimum" Data Reporting Requirements

The table, below, indicates the "at a minimum" information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short-circuit**
1. Each Bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand at each bus [LSE] a. real and reactive power* b. in-service status* c. load type (e.g., firm, interruptible, scalable, etc.) 3. Generating Units[2] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* e. voltage set point* (as provided to the GO by the TOP) f. owner(s) information (including percentage of ownership if jointly owned) g. machine MVA base	1. Generator [GO] a. Synchronous machines, including, as appropriate to the model: i. inertia constant ii. damping coefficient iii. saturation parameters iv. direct and quadrature axes reactances and time constants b. Other technologies, including, as appropriate to the model: i. inertia constant ii. damping coefficient iii. saturation parameters iv. direct and quadrature axes reactances and time constants	1. Positive Sequence Data – provide for all applicable elements in column "steady-state" [GO, TO] 2. Negative Sequence Data – provide for all applicable elements in column "steady-state" [GO, TO] 3. Zero Sequence Data – provide for all applicable elements in column "steady-state" [GO,TO] a. Bus b. Generator c. Transmission line d. Transformer (to include connection type) 4. Mutual Line Impedance Data [TO]

[1] For purposes of this attachment, the functional entity references are represented by abbreviation as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Operator (TOP), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] Including synchronous condensers, pumped storage, etc.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short-circuit**
h. share of reactive contribution for voltage regulation* i. generator step up transformer data (provide same data as that required for transformer under item 6, below) j. generator prime mover and fuel type (hydro, wind, fossil, solar, nuclear, etc) 4. AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO] a. impedance (positive sequence) i. resistance ii. reactance iii. susceptance (line charging) b. ratings (normal and emergency)* c. equipment status* 5. DC Transmission systems – identified by DC line name or number [TO] a. AC bus number and name for each converter b. line parameters c. ratings d. rectifier and inverter data 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. regulated voltage limits or MW band limits* h. ratings (normal and emergency)* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* e. share of reactive contribution for voltage regulation* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed shunt switching, if applicable	2. Excitation System [GO] 3. Governor [GO] 4. Power System Stabilizer [GO] 5. Demand [LSE] (consistent with system load representation (composite load model) and components as a function of frequency and voltage) 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short-circuit**
d. share of reactive contribution for voltage regulation* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

If a Transmission Planner and Planning Coordinator mutually agree, a Transmission Planner may collect and aggregate some or all data from providing entities, and the Transmission Planner may then provide that data directly to the Planning Coordinator(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

An entity submitting data per the requirements of this standard who need to determine the PC for the area, as a starting point, should contact the local TO for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a GO) is requesting interconnection for a new generator, the entity can determine who the PC is for that area at the time a generator interconnection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the three interconnections (Eastern, ERCOT and WECC). Presently, the Eastern and Texas Interconnections on an annual basis build seasonal cases, while the WECC Interconnection builds cases on a continuous basis throughout the year. 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 model(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection model(s).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR posted for comment (Dates of posting TBD).

Description of Current Draft

This is the first posting of this standard for a 45-day formal comment period and initial ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-032-1 seek to address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee’s System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Initial Ballot	July 2013
Recirculation ballot	September 2013
BOT adoption	November 2013

Effective Dates

In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after Board of Trustees approval.

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**
2. **Number: MOD-033-1**
3. **Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building of models to analyze the reliability of the interconnected transmission system.**
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinators

   4.1.2 Reliability Coordinators

   4.1.3 Transmission Operators

5. **Background:**

MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires a minimum level of data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the interconnection model building process in their interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the PC to implement a documented process to validate data for steady state and dynamic models within its area, which is consistent with the Commission directives. The validation of the full interconnection model is left up to the ERO or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of power flow model to state estimator snapshot; and

B. Simulation of significant system disturbances and comparing the simulation results with the actual event results.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to the criteria listed without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Part 1.3 supports confirming or correcting the model for accuracy in coordination with the data owner when the actual system response does not match expected system performance, which could be accomplished through use of MOD-032-1, Requirement R4, if necessary.

R1. Each Planning Coordinator must implement a documented process to validate the data used for steady state and dynamic analyses (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses that includes, at a minimum, the following items: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Validate its portion of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other Real-time data sources to check for discrepancies that the Planning Coordinator determines are large or unexplained at least once every 24 calendar months through simulation.

1.2. Validate its portion of the system in the dynamic models at least once every 24 calendar months through simulation of a dynamic local event, unless the time between dynamic local events exceeds 24 calendar months. If the time between dynamic local events exceeds 24 calendar months, validate its portion of the system in the dynamic models through simulation of the next dynamic local event. Complete the simulation within 12 calendar months of the local event.

1.3. Coordinate with the data owner(s) to confirm or correct the model for accuracy when the discrepancy between actual system response and expected system performance is too large, as determined by the Planning Coordinator.

M1. Examples of evidence may include, but are not limited to, a documented validation process and evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual real time system data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

R2. Each Reliability Coordinator 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 that the Planning Coordinator requests to perform validation under Requirement 1 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 but did validate in less than or equal to 28 calendar months; OR The Planning Coordinator did not complete simulation of the local event within 12 calendar months in validating its portion of the system in the dynamic models as required by R1 but did complete the simulation in less than or equal to 15 calendar months.	The Planning Coordinator documented and implemented a process to validate data but did not address one of the three required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 but did validate in greater than 28 calendar months but less than or equal to 32 calendar months; OR The Planning	The Planning Coordinator documented and implemented a process to validate data but did not address two of the three required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 but did validate in greater than 32 calendar months but less than or equal to 36 calendar months; OR The Planning	The Planning Coordinator did not have a validation process at all or did not document or implement any of the three required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 or did validate but exceeded 36 calendar months between validation; OR The Planning Coordinator did not complete simulation of the local event at all in

				Coordinator did not complete simulation of the local event within 12 calendar months in validating its portion of the system in the dynamic models as required by R1 but did complete the simulation in greater than 15 calendar months but less than or equal to 18 calendar months.	Coordinator did not complete simulation of the local event within 12 calendar months in validating its portion of the system in the dynamic models as required by R1 but did complete the simulation in greater than 18 calendar months but less than or equal to 21 calendar months.	validating its portion of the system in the dynamic models as required by R1 or did complete the simulation but exceeded 18 calendar months.
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting planning coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting planning coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting planning coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in	The Reliability Coordinator or Transmission Operator did not provide any requested actual system behavior data (or a written response that it does not have the requested data) to a requesting planning coordinator; OR The Reliability Coordinator or Transmission Operator did not provide

			less than or equal to 45 calendar days.	greater than 45 calednar days but less than or equal to 60 calendar days.	greater than 60 calednar days but less than or equal to 75 calendar days.	requested actual system behavior data (or a written response that it does not have the requested data) to a requesting planning coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 calednar days but less than or equal to 60 calendar days.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the criteria specified in the requirement. For further information on suggested validation procedures, see "Procedures for Validation of Powerflow and Dynamics Cases" produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is encouraged to develop and include in its process criteria for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are too large or unexplained.

For the validation in part 1.1 the state estimator case should be taken as close to system peak as possible. However, other snapshots of the system could be utilized if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies "once every 24 calendar months," entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the PC should consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator's planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole interconnection.

The validation required in part 1.2 should include simulations which are to be compared with actual system data and may include comparisons of:

- Voltages oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Part 1.3 could be accomplished in direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R4 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected.

While the validation is focused on the PC's planning area, the model to be used for the validation should be one that contains a wider area of the interconnection than the PC's area. If the simulations can be made to match the actual system responses by reasonable changes to the data, then the PC should make those changes in coordination with the data provider. However, for some disturbances, the data in the PC's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the ERO. If a model with estimated data or a generic model is used for a generator and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

July 18, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards
MOD-032-1 – In those jurisdictions where regulatory approval is required, Requirements R1 and R2 shall become effective on the first day of the fourth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the fourth calendar quarter after Board of Trustees approval, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after Board of Trustees approval.

MOD-033-1 – In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after Board of Trustees approval.

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirements R1 and R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements
MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, “. . . at least once every 24 calendar months . . .”, and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Standards Authorization Request Form

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Modification of MOD-010 through MOD-015		
Date Submitted:	12/12/2012		
SAR Requester Information			
Name:	John Simonelli, Chair, on behalf of the System Analysis and Modeling Subcommittee		
Organization:	System Analysis and Modeling Subcommittee		
Telephone:	404-357-9843	E-mail:	steven.noess@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability):
This SAR proposes modifying the current standards MOD-010 through MOD-015 by combining them into a fewer number of standards. This project will resolve FERC Order No. 693 directives relating to MOD-10 through MOD-15. The combined standards should be improved and strengthened to include additional requirements for the supply of data and models that specify the responsible functional entities, criteria for acceptability, standard formatting, and shareability. Short circuit data requirements should also be added to support the latest draft of the TPL-001-2 standard.
Industry Need (What is the industry problem this request is trying to solve?):
Models are the foundation of virtually all power system studies. Calculation of operating limits, planning studies for assessment of new generation and load growth, and performance assessments of system integrity protection schemes are but some of the studies that depend on accurate mathematical representations of transmission, generation, and load. The current standards have several limitations in three broad categories that should be addressed:

SAR Information

• Needed MOD standards are not approved
  ○ MOD-011, MOD-013, MOD-014 and MOD-015 were not approved by FERC Order No. 693 and remain in "pending" state due to their "fill-in-the-blank" nature, with requirements applicable to Regional Reliability Organizations (RROs).
  ○ Approved standards MOD-010 and MOD-012 refer to specific modeling needs and processes outlined in unapproved standards MOD-011 and MOD-013 respectively.
• Approved MOD standards require clarification
  ○ The approved MOD standards lack clear delineation of responsibilities for providing and receiving needed data and models.
  ○ The approved standards lack specificity. For example, the standards do not describe the quality and usability that the provided models must have for static and dynamic conditions.
• The MOD standards should be strengthened
  ○ Newer Reliability Standards such as TPL-001-2 require a level of modeling not supported by the approved MOD standards.
  ○ The approved standards do not support the increased modeling demands of new technologies (e.g., renewable resources).
  ○ The absence of cogent modeling standards makes it difficult to identify the source of emerging Interconnection-wide issues (such as declining frequency response), and to perform event analysis for large system disturbances.
Furthermore, the Power System Model Validation White Paper by the NERC Model Validation Task Force (MVTF) of the Transmission Issues Subcommittee (TIS) recommended that "The NERC MOD standards on powerflow and dynamics data (MOD-010 through MOD-015) should be improved and strengthened."

Brief Description (Provide a paragraph that describes the scope of this standard action.)

1. The quantity of MOD standards should be reduced by combining the existing standards MOD-010 through MOD-015 into a fewer number of standards (such as one for steady state and one for dynamics).
2. Short Circuit Data requirements should be added to support the latest draft of the TPL standard (TPL-001-2).
3. Additions should be made to the requirements to supply data and models.
  a. The correct functional entities that are responsible to provide data and models or receive them should be identified. References to the RRO as the applicable entity should be removed from any existing or new requirements.
  b. Criteria for acceptability should be identified for supplied data and models.
  c. A standard format should be specified for supplied data.

SAR Information
d. New technology model requirements should be included. e. Shareability of proprietary models should be addressed.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
All devices and equipment attached to the electric grid must be modeled to accurately capture how that equipment performs under static and dynamic conditions. There have been issues with proprietary models and the ability to share across sectors. Many generator manufacturers, notably wind turbine manufacturers, wish to keep the dynamics properties of their equipment confidential. As most areas are experiencing a surge in wind penetration, obtaining accurate dynamics model data for wind farms is becoming increasingly difficult, if not impossible. Similar challenges are also associated with modeling of utility-grade photovoltaic installations. Generator Owners must provide accurate model data of their systems during the interconnection process. This information is critical to ensure that their power generating systems can be safely integrated into the electric grid. However, many of those accurate model datasets submitted for use in the interconnection process cannot be used for any other modeling endeavors due to non-disclosure agreements or pro forma tariff language concerning use of confidential information. These generator owners state that industry sensitive data is contained in their datasets and therefore cannot be divulged to anyone outside the interconnecting utility. This precludes use of those data and models in Interconnection-wide powerflow and dynamic analysis, which is crucial to understanding how the connecting equipment will interact with the rest of the system. Similar situations are arising with the models for wind turbines, photovoltaic inverters, and other power electronic devices. When a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection. Several improvements to MOD-010 through MOD-015 are outlined below. The standards development process will naturally need to consider parallel developments in other projects (such as Project 2007-09 Generator Verification) as well as requirements in other existing standards (such as IRO-010-1a and TOP-003-2). It may be desirable to move modeling requirements from other standards into the revised MOD standards. Furthermore, industry best practices and existing processes should be considered in the development of requirements, as many entities are successfully coordinating their efforts.

SAR Information
1. *Reduce the quantity of MOD Standards*
MOD-010 through MOD-015 should be combined into a fewer number of standards, such as one standard for steady state and one for dynamics. However, it may also be useful to develop separate standards for equipment data collection (for the purpose of building needed steady-state and dynamic models) and the construction and validation of solved cases. MOD-011 and MOD-013 could be eliminated, but needed requirements from these standards should be moved into MOD-010 and MOD-012 respectively (or a comparable standard or set of standards).
MOD-010-0 clearly states that responsible entities (including Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners) must provide the needed steady state data and models in accordance with requirements that are provided in MOD-011-0. If MOD-011-0 is eliminated, then MOD-011-0 R1.1 through R1.7 must be included in a revised MOD-010 (or comparable standard). Further, a revised MOD-010 must include requirements for Planning Coordinators and Reliability Coordinators to provide the needed data, models and assembled cases to the Regional Entities and ERO (upon request or on a schedule) to facilitate the development of Interconnection-wide steady-state modeling cases.
MOD-012-0 contains requirements that responsible entities (including Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners) shall provide appropriate equipment characteristics, system data, and dynamics system modeling and simulation data in compliance with the respective Interconnection-wide requirements and reporting procedures. Further, the standard requires that the responsible entities must have evidence that they complied with the Interconnection-wide requirements and reporting procedures.
MOD-012-0 also states that the responsible entities (including Generator Owners) must provide the needed data and models in accordance with requirements that are provided in MOD-013. If MOD-013 is eliminated, then the specifics provided in MOD-013-1 R1.1, R1.2, R1.3, R1.4, and R1.5 must be included in MOD-012. Further, MOD-012 must include requirements for Planning Coordinators and Reliability Coordinators to provide the needed data, models and assembled cases to the Regional Entities and ERO (upon request or on a schedule) to facilitate the development of Interconnection-wide dynamics modeling cases.
A revised MOD-012 (or comparable standard) should account for the current MOD-013-1 provision that allows for responsible entities to provide estimated or typical manufacturer dynamics data based upon

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criteria provided in the Interconnection-wide procedures.[1] A comparable provision should be included in a revised standard, but the requirements should be strengthened by specifying (and limiting) the instances when generic manufacturer data is accepted. For example, estimated or typical data could be accepted on a temporary basis, or upon documented agreement between entities when the impact is shown to be negligible; however, it is not possible to determine the impact without a sufficient model. A stronger, FERC-approved standard could ultimately resolve some of the issues associated with the use of generic manufacturer data for equipment, including wind turbines. **2. *Add Short Circuit Data to MOD Standards*** Short circuit analysis is required in the approved FAC-002-1 standard and the latest draft of the TPL-001-2 standard.[2] While the development of Interconnection-wide short-circuit modeling cases is not necessary and should not be required in a standard, the standards must require that neighboring entities share a sufficient level of short-circuit data to enable the studies required by the existing and future standards. **3. *Add to the Requirement to Supply Data and Models*** **a. *Identify responsibility to provide and identify who is responsible to receive*** A model of the power system requires data that includes but is not limited to: loads, transmission lines, transformers, shunt devices, generators, stacking order for dispatching generators, and interchanges of power. Such data must be supplied by various functional entities as shown in the table below. This data must be supplied to Planning Coordinators, Transmission Planners, Transmission Operators, and Reliability Coordinators as applicable. The Planning Coordinator or Transmission Planner should be responsible for putting all of the data together in a power flow case with associated dynamics data. These assembled cases should then be supplied to the Regional Entities and ERO, who can then combine cases to develop an Interconnection-wide case.

[1] MOD-013-1 R1.2.1 states: "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."

[2] See FAC-002-1 R1.1.4 and TPL-001-2 R2.3 & R2.8. See also page 209 in Project 2010-03 Modeling Data.

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Table 2: Data Responsibilities

Data	Responsible for Providing Data & Models	Delivers To
Load Forecast	LSE	PC, TP, TOP, RC
Transmission Data	TO	PC, TP, TOP, RC
Generator Data	GO	PC, TP, TOP, RC
a. Resource Projections b. Generation stacking order	RP	PC, TP, TOP, RC
Interchange	TSP, BA	PC, TP, TOP, RC
Complete cases/models	PC, TP	ERO, RE

b. *Identify acceptability*

The present MOD standards provide little to no specification on whether a particular set of model data meets the requirements of the standards. The group recommends the following changes to the standards to identify acceptability:

- For powerflow models, the standards should specifically list all of the parameters which must be provided. For some parameters, it may be desirable to include established norms (for example, a typical range for transmission line impedance per mile at a given voltage). For these parameters, the data should either conform to established norms, or a statement attesting to unusual values should be provided. Data for new equipment should be tested in a standard library powerflow case by performing a solution to test convergence and reasonableness. Model data for a particular piece of equipment should be consistent across all applications that use that data. When available, the model data for the equipment should be from vendor-certified test reports or field tests. If a novel device is required to be represented by a user-written model, the standards should mandate that all of the equations describing the characteristics and logic of the model must be provided, along with any other descriptive information. Additionally, the data provided by asset owners needs to meet model validation standards such as MOD-026 and MOD-027 and any additional standards that arise from the work of the NERC Model Validation Working Group (MVWG).

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• For dynamics models, a standard, industry-recognized model name and a set of parameter values must be provided. If a standard, industry-recognized model is not available, the standards should specify that the asset owner must provide a block diagram, equations describing the characteristics of the model, values and names for all model parameters, and a list of all state variables. Furthermore, it should be required that, if a standard model is not available, the owner should develop the non-standard model in the format needed by the Transmission Planner or Planning Coordinator. The standards also need to specify that this information will be shared on an Interconnection-wide basis. Proprietary models with details hidden from the user ("black box" models) or those models that cannot be shared across the Interconnection are not acceptable.[3] Engineers performing power system studies need access to all of the model information in order to properly analyze the reliability and operating characteristics of the power system. To the extent practical, the revised MOD standards should include a list of specific data that is required. Preference should be given to IEEE standard models where such models are suitable representations of the equipment being modeled. Additionally, the data provided by asset owners needs to meet model validation standards such as MOD-026 and MOD-027 and any additional standards that arise from the work of the NERC MVWG. • The standards must also specify that the asset owner will provide models with additional detail and specificity to any Planning Coordinator upon request for its own internal studies. **c. *Standard format*** The specification and use of a standard format or set of formats enables data to be exchanged easily between involved entities (e.g., PCs, TPs, TOPs, RCs, TOs, GOs, LSEs, RPs) and helps support the accurate development of steady state, short circuit, and dynamic base cases. Having a standard format allows the development and aggregation of base cases which cover large areas such as the four Interconnections in North America. Each vendor has their own data format, some of which are translatable between vendors. However, some translations are only useful for steady-state analysis. Dynamics data does not translate well between vendors. The MOD standards should incorporate industry standard formats for all steady-state, short-circuit, and dynamics data, and the standard formats should be approved via the NERC standard development process. A translation of a specific vendor format to the common format is acceptable provided the resulting data has been validated.

[3] As noted in Section 1 and footnote 1, concessions could be considered for the acceptance of generic manufacturer data, if proven to be working and useful, based on whether it is used on a temporary basis or when the impact is shown to be negligible, for example.

SAR Information
NERC should lead the development of test cases to validate the translation of the vendor format to the common format. If a specific vendor format is not translatable to the approved common format then it does not comply with the standard. Coding for generic block diagrams should be included. The NERC Model Validation Working Group also recommends standardizing data exchange formats. **d.** ***How to deal with new technology (require a user-written model if no standard model exists)*** Presently, models for new technology equipment are introduced in a non-uniform manner. Equipment manufacturers and other outside interests have internally created a proliferation of non-standard equipment models. These models thus lack sufficient input from the individuals who study reliability and operating characteristics of the power system. These models were inserted into production studies without vetting from recognized technical authorities such as the IEEE. Many of these models are proprietary and distributed as “black box” object code modules for specific simulation programs. Models for new technology must include information comparable to existing models in common use. Powerflow models need to include the equations describing the characteristics of the equipment being modeled. For dynamics, a block diagram is essential. Ideally, the industry should collaboratively develop model structures which include those elements that are of importance in power system studies. Such an effort would enable consistent development of useful models while simultaneously protecting manufacturer interests regarding confidential trade secrets of implementation details that are not relevant to power system studies. Equipment should not be allowed to connect to the grid if the models lack the information needed for performing appropriate reliability and operating characteristics assessments. All responsible entities including Transmission Owners and Generator Owners must be held accountable for providing the information needed to maintain power system reliability. **e.** ***Shareability (an issue tangential to the MOD standards)*** One of the problems identified in the *Power System Model Validation White Paper* is that there are legal and procedural issues that inhibit the gathering and distribution of model data among stakeholders. The report cites FERC CEII (critical energy infrastructure information) requirements and proprietary issues that result in claims of the need for confidentially. The report noted that in particular, Generator Owners of wind turbines are unable to provide unit specific data due to wind turbine manufacturer statements that the dynamics models of their equipment must be held confidential. This is particularly problematic in areas that are experiencing a surge in wind penetration.

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One possible approach to address proprietary model issues is for the Generator Owner to work with the vendor to develop a generic model that can be shared across the Interconnection. In such a case, the standard should specify that the Generator Owner is responsible for reviewing and submitting supporting simulations performed by the vendor that demonstrate and certify a provided generic model will accurately simulate the generator (or any other device in question) for system level studies. The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary. Another approach is for NERC and/or FERC to hold a technical conference where wind turbine manufacturers will be asked to give explanations for keeping their models proprietary while NERC staff and members of NERC subcommittees describe why detailed models are required. Following such a technical conference, NERC and FERC could consider subsequent steps that could result in a FERC Notice of Inquiry or Notice of Proposed Rulemaking on the subject.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☒	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.

Reliability Functions		
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and Reactive Power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

Reliability and Market Interface Principles	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
IRO-010-1a	Identifies the high-level process that must be followed to ensure that RCs are provided with models. This standard could be considered for consolidation into revised MOD standards.
TOP-003-2	Identifies the high-level process that must be followed to ensure that BAs and TOPs are provided with models. This standard could be considered for consolidation into revised MOD standards.

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-03 Modeling Data

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft MOD-032-1 and MOD-033-1 standards. The electronic comment form must be completed by 8:00 p.m. ET on **DATE**

If you have questions please contact Steven Noess via email or by telephone at 404-446-9691.

The project page may be accessed by clicking here.

Background Information

NERC Reliability Standards MOD-010 through MOD-015 address modeling data requirements that support the mathematical model representations of transmission, generation, and load that are the foundation of virtually all power system studies. Only two of those standards were approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Order No. 693. Four of them were neither approved nor remanded, and they remain in a pending status.

NERC initiated an informal development process ("MOD B") to address the remaining directives related to the existing standards from FERC Order Nos. 890 and 693. Resulting from informal development, two new reliability standards are proposed to replace MOD-010 through MOD-015. The proposal includes a combined modeling data standard, MOD-032-1, and a new validation standard to address directives related to validation, MOD-033-1.

The proposed standards are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires a minimum level of data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection model building process in their Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

This posting is soliciting comment on a proposed Reliability Standards MOD-032-1 and MOD-033-1 and a Standard Authorization Request (SAR).

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you have any specific questions or comments relating to the scope of the proposed standard action or any component of the SAR outside of the pro forma standard?

☐ Yes
☐ No

Comments:

2. Proposed MOD-032-1 (Data for Power System Modeling and Analysis) consolidates and replaces the topics previously addressed by MOD-010 through MOD-015, in addition to incorporating improvements and approaches to meet remaining directives. Do you agree with the approach in MOD-032-1?

☐ Yes
☐ No

3. If you have any specific comments on MOD-032-1, please indicate them here.

Comments:

4. Proposed MOD-033-1 (Steady-State and Dynamic System Model Validation) addresses validation, in part to meet remaining directives related to validation. Do you agree with the approach in MOD-033-1?

☐ Yes
☐ No

5. If you have any specific comments on MOD-033-1, please indicate them here.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Informal Development Background of the MOD B Standards

July 18, 2013

RELIABILITY | ACCOUNTABILITY

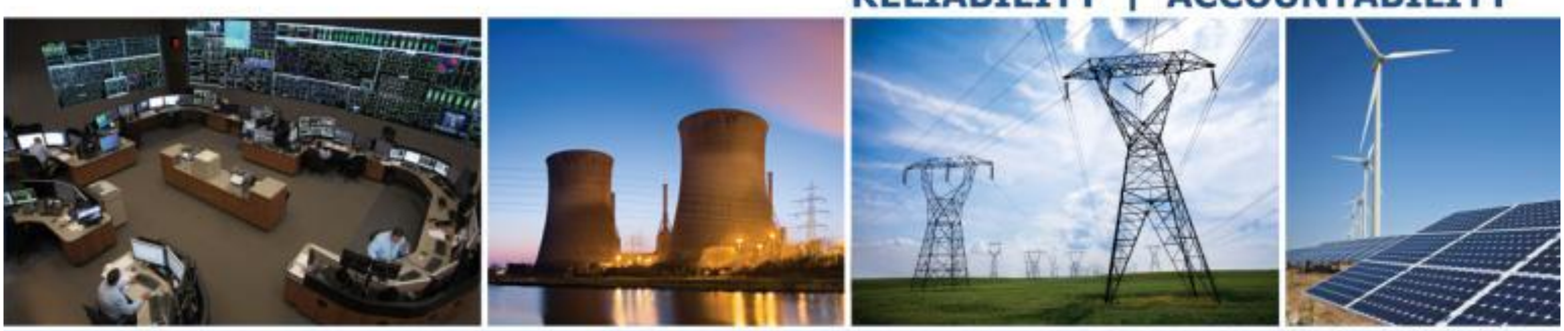

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Table of Contents

Executive Summary

This document provides a summary and information regarding the informal development efforts of the MOD B ad hoc group. A separate, thorough white paper and recommendations regarding MOD-010 through MOD-015 was completed by the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS) (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf). Additionally, that whitepaper provided significant input into the technical background and discussion included within the Standards Authorization Request (SAR), and, for those reasons, a more thorough technical discussion of MOD-010 through MOD-015 is not repeated in this document.

NERC Reliability Standards MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 (referred to herein as the "existing MOD B standards") address modeling data requirements that support the mathematical model representations of transmission, generation, and load that are the foundation of virtually all power system studies. Of the six existing MOD B standards, only two were approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Order No. 693. Four of them were neither approved nor remanded, and they remain in a pending status. The following provides a brief summary and status of the existing MOD B standards:

- The existing MOD B Standards
    - MOD-010-0—Steady-State Data for Modeling and Simulation of the Interconnected Transmission System
    - MOD-011-0—Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures
    - MOD-012-0—Dynamics Data for Modeling and Simulation of the Interconnected Transmission System
    - MOD-013-1—Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures
    - MOD-014-0—Development of Steady-State Models
    - MOD-015-0.1—Development of Dynamics System Models
- Four existing MOD B standards are not approved
    - MOD-011, MOD-013, MOD-014 and MOD-015 were not approved by FERC Order No. 693 and remain in "pending" state due to their "fill-in-the-blank" nature, with requirements applicable to Regional Reliability Organizations (RROs).
    - Approved standards MOD-010 and MOD-012 refer to specific modeling needs and processes outlined in unapproved standards MOD-011 and MOD-013, respectively.
- FERC directives regarding the existing MOD B standards remain unaddressed (discussed in detail later in this document)
    - FERC Order No. 890 (issued February 2007): 1 directive unaddressed
    - FERC Order No. 693 (issued March 2007): 12 directives unaddressed

NERC initiated an informal development process to address the remaining directives related to the existing MOD B standards from FERC Order Nos. 890 and 693. Participants were industry subject matter experts, NERC staff, and staff from FERC's Office of Electric Regulation. In discussing the existing MOD B standards during industry outreach, the informal effort proposed creation of two new reliability standards to replace the existing MOD B standards. The proposal included in this SAR package includes a combined modeling data standard, MOD-032-1, and a new validation standard to address directives related to validation, MOD-033-1 (collectively referred to herein as "proposed MOD B standards"). The proposed MOD B standards are as follows:

- MOD-032-1—Data for Power System Modeling and Analysis
- MOD-033-1—Steady-State and Dynamic System Model Validation

In preparing proposals to address the outstanding directives and proposed improvements to MOD-010 through MOD-015, the ad hoc group ensured that the requirements in the proposals were results-based and considered criteria from the Paragraph 81 project (Project 2013-02 Paragraph 81).

The group considered the criteria from the Paragraph 81 project to ensure that the standards proposals did not create requirements that meet those criteria. The Paragraph 81 project also prepared a "Paragraph 81 Project Technical White Paper," dated December 20, 2012, that includes discussion of the identifying criteria that must be satisfied before a

Reliability Standard requirement may be proposed for retirement.[1] Specifically, for a Reliability Standard requirement to be proposed for retirement, it must satisfy *both* the overarching criterion that it requires an activity or task that does little, if anything, to benefit reliability *and* additional identifying criteria (such as criteria that it is administrative, reporting, redundant, etc., as discussed in the Paragraph 81 Technical White Paper).[2]

In comments submitted to the Paragraph 81 project, there were some comments proposing retirement of requirements in existing MOD-010 and MOD-012 related to reporting data to the RROs on the basis that they were administrative or reporting requirements, or that the information could be collected via vehicles other than a Reliability Standard. In creating the proposed MOD B standards, the ad hoc group carefully considered these suggestions. The proposed MOD B requirements specify who must provide specific types of data to whom for purposes of supporting the system-wide Interconnection models. Importantly, with respect to modeling, providing modeling data itself supports reliability objectives. The paragraph 81 identifying criterion for administrative requirements (criterion B1) applies when the requirement "requires responsible entities to perform a function that is administrative in nature, *does not support reliability* and is needlessly burdensome."[3] Similarly, the identifying criterion for reporting requirements (criterion B4) applies to requirements that obligate responsible entities to report to a Regional Entity, NERC, or another party or entity "on activities *which have no discernible impact on promoting the reliable operation of the BES* and if the entity failed to meet this requirement there would be little reliability impact."[4] Absence of modeling data for use in the Interconnection models would be expected to have a reliability impact, and the requirements in the proposed MOD B standards do not create requirements that meet the Paragraph 81 criteria because they establish consistent modeling data requirements and reporting procedures to support analysis of the reliability of the interconnected transmission system.

The proposed MOD B standards are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires a minimum level of data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection model building process in their Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The modeling data standard proposal, MOD-032-1, is intended to provide clear expectations of "who" provides "what" data to "whom." It does not prescribe the model building itself, as there are other requirements, namely from TPL-001-4, that address certain Planning Coordinator (PC) and Transmission Planner (TP) obligations in model building. Instead, the standard focuses on modeling data in support of, ultimately, the building of each Interconnection model. The requirements specify the "at a minimum" data that must be provided by each data owner.

MOD-032-1 also recognizes the differences among Interconnections in model building processes, but creates an obligation for PCs to provide the collected data in a manner that accounts for those differences. It specifies that PCs must submit the modeling data to the "ERO or its designee" to support the Interconnection model building process in the submitting PC's particular planning area.

While different entities in each Interconnection create the Interconnection model, the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration with other organizations, can designate the appropriate organizations in each Interconnection to build the Interconnection-specific model. It does not prescribe a specific group or process to build the larger Interconnection models, but only requires the PCs to submit data in support of the models' creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards referenced earlier (at page 3 of that whitepaper) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (emphasis added).

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[1] *Paragraph 81 Project Technical White Paper*, December 20, 2012. Available at http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20RF/P81_Phase_I_technical_white_paper_FINAL.pdf.

[2] See *Id.* at p. 7 and 8.

[3] *Id.* at p. 8. (Emphasis added).

[4] *Id.* at p. 9. (Emphasis added).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Quebec and Eastern Interconnection models, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection models, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection models. This standard does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the “designee” for each Interconnection. Similarly, the requirement does not prohibit transition, and the standard would not likely need to be updated if the Interconnection model building process changed in the future.

MOD-033-1 is a new standard focused on PC-level system validation within each PC’s planning area. At its core, the standard establishes a requirement for each PC to implement a documented process to validate data for steady state and dynamic models within its area, which is consistent with the Commission directives. The validation of the full Interconnection model is left up to the ERO or its designees, and is not addressed by this standard.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this standard focuses on the Planning Coordinator performing validation pursuant to the required criteria without specifying the details of “how” it must validate, which is necessarily dependent upon facts and circumstances.

History of the MOD B Informal Development

Ad Hoc Group Meetings

The MOD B informal development group—a small group of industry subject matter experts, NERC standards staff, NERC reliability initiatives and systems analysis staff, and participants from FERC staff—met face to face several times to discuss the proposals and the outstanding directives from FERC Order Nos. 890 and 693 as follows:

- February 12-14, 2013 at NERC's Washington, D.C. office.
- March 13-14, 2013 in Atlanta, GA.
- April 9-10, 2013, in Washington, D.C.
- April 17-18 in Baltimore, MD.
- June 12-13 at NERC's Atlanta, GA office.

Other Outreach

There were three technical workshops in support of the MOD B informal development efforts. The purpose of these one-day workshops was to encourage industry participation and to gain industry insight into the topics addressed by the proposed MOD B standards. The three workshops were strategically placed within the western, central, and eastern locations of North America. The first one-day workshop occurred on May 9, 2013, in Minneapolis, Minnesota. There were 50 in-person attendees and 277 online registrants. The second one-day workshop occurred on June 18, 2013, in Salt Lake City, Utah. There were almost 40 in-person attendees and 186 online registrants. The third one-day workshop occurred on June 25, 2013 in Baltimore, Maryland. There were approximately 20 in-person attendees and 199 online registrants.

Topics of the workshops included:

- Informal development background
- The current practices and associated recommendations for the MOD-010 through MOD-015 standards;
- Approaches for each of the Modeling Data and Validation standard proposals and the responsibilities in these proposals as applied to various functional entities;
- Roles of the Planning Coordinator and Transmission Planner in the new standards;
- Interconnection model building impacts; and
- Participant-focused question and answer sessions.

The MOD B ad hoc group also conducted an industry webinar on April 12, 2013 which had 412 online registrants.

Outstanding Directives from FERC Order 890

Para 290

The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.

Consideration of Issue or Directive

The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R4 provides a feedback loop for issues of data from the data owners.

The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by the MOD A effort.

Outstanding Directives from FERC Order 693

Para 1148

Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.

Consideration of Issue or Directive

For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.

Para 1154

We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.

Consideration of Issue or Directive

For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.

Transmission Operator has also been added as an applicable entity in MOD-032-1.

Para 1155

We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.

Consideration of Issue or Directive

The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the Interconnection models, and validating models relative to their planning areas.

The referenced attachment 1 specifies the specific "at a minimum" data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, Interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and Interconnection.

Para 1662

We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.

Consideration of Issue or Directive

See the response to Paragraph 1155.

Para 1178

Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.

Consideration of Issue or Directive

For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.

Para 1183

We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the transmission planner to provide fault and disturbance lists.

Consideration of Issue or Directive

For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.

For the second part of the directive, the Transmission Operator has been added as an applicable entity in MOD-032-1.

Para 1184

We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.

Consideration of Issue or Directive

See response to paragraph 1155.

Para 1197

We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.

Consideration of Issue or Directive

This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'"

This is being addressed by MOD-032-1, Requirement R4, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Para 1199

We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

Consideration of Issue or Directive

See response to paragraph 1155.

Para 1210

We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.

Consideration of Issue or Directive

Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses.

Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.

Para 1211

Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.

Consideration of Issue or Directive

Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement 1.1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response.

In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).

Para 1220

We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be validated against actual system responses.

Consideration of Issue or Directive

See response to paragraph 1210.

Conclusion

The informal development for the MOD B initiative provided key input into the proposed MOD B NERC Reliability Standards. In conjunction with the informal outreach, discussions, presentations, and technical conferences, the MOD B informal effort was able to begin addressing issues early. Informal outreach provided an efficient and open venue to consider myriad perspectives, build consensus, and engage in important dialogue. The result is a set of two new MOD reliability standards that represent input from virtually every corner of the electric industry, and time, effort, and discussion spent on upfront informal development was instrumental in quickly resolving points that may have otherwise taken significantly more time during formal development.

Appendix A: Entity Participants

The below entities represent a non-exhaustive list of entities that had personnel that participated in the MOD B informal development effort in some manner, which may include one of the following: direct participation on the ad-hoc group, inclusion on the wider distribution (the "plus" list), attendance at workshops or other technical discussions, participation in a webinar or teleconference, or by providing feedback to the group through a variety of methods (e.g., email, phone calls, etc.). Additionally, though not listed here, announcements were distributed to wider NERC distribution lists to provide the opportunity for entities that were not actively participating to join the effort.

Table 1: Entity Participation in MOD B Informal Development

ACES Power	Comed	GTC	MISO	Seminole Electric	
AECI	ConEd	Hydro Quebec	MPW	Sempra Utilities	
AEP	CPS	IESO	National Grid	SF Water	
Alcoa	CPS Energy	IID	NaturEner	SMUD	
Ameren	CSU	IMEA	NIPSCO	Southern Company	
APS	Delmarva	ISONE	Northeast Utilities	SPP RC	
ATC	Dominion	ITC	Northwestern	SRP	**Regional Entities**
Austin Energy	Duke	JEA	NYISO	Sunflower	FRCC
Avista	Duquesne Light	KCPL	NYPA	SW Transco	MRO
BC Hydro	Dynegy	KEPCO	ODEC	TEP	NPCC
BEPC	EKPC	LBWL	OGE	Trans Bay Cable	RFC
Black Hills Corp	Entegra	LCPUD	OMPA	Tres Amigas LLC	SERC
BPA	Entergy	LCRA	OTPCO	TVA	SPP
Brazos Electric	ERCOT	LGE & KU	PacifiCorp	Vectren	TRE
Centerpoint Energy	Exelon	Lonestar Transmission	Pepco	WAPA	WECC
City of Glendale	FMPA	Luminant	PGE	We Energies	
City of Tacoma	Fortis BC	MAPP	PPL	WECC RC	
CMS Energy	FPL	MEAG Power	PSEG	Westar	
Cogentrix	GRDA	MGE	Quanta Technology	Wisconsin Public Service	
Columbia Grid	GRE	MidAmerican	SaskPower	WPSCI	
			SCE	Xcel Energy	

Table 2: Presentations and Events	
EPRI Power Plant meeting	North American Transmission Forum (NATF) Modeling Practices Group (MPG)
ERAG Management Committee	NPCC Compliance and Standards Spring Workshop
ERAG Multi-regional Modeling Working Group (MMWG)	NPCC Regional Standards Committee
GE PSLF users group	NPCC's Base Case Development working group (SS-37)
MRO Model Building Subcommittee	Siemens PSS/E Users Group
MRO Reliability Workshop	Southern-Florida Planning Group
NERC Modeling Working Group	Southwest Power Pool (SPP) Model Development Working Group (MDWG)
NERC NEWS	Various Regional Operating Committee
NERC Operating Committee	Various Regional Planning Committees,
NERC Planning Committee	Various Regional Standards Committees
NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS)	WECC Modeling & Validation WG
NERC Standards Committee	

Consideration of Issues and Directives

MOD B

Working Draft, July 9, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R4 provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by the MOD A effort.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		Transmission Operator has also been added as an applicable entity in MOD-032-1
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific “at a minimum” data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as	FERC Order No. 693	See the response to Paragraph 1155.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission planner to provide fault and disturbance lists.		For the second part of the directive, the Transmission Operator has been added as an applicable entity in MOD-032-1
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" This is being addressed by MOD-032, Requirement R4, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
estimates at the regional level. That said, the Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement 1.1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
actual system performance and the model should be small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		between actual system performance and the model do not exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be	FERC Order No. 693	See response to paragraph 1210.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
simulated and dynamics system model output be validated against actual system responses.		

MOD B

Working Draft (July 9, 2013) of Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R3	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R3	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators, in conjunction with each of its Transmission Planners, to develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit “at a minimum” requirements.

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators, in conjunction with each of its Transmission Planners, to develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit "at a minimum" requirements. MOD-032-1, Requirement R2 maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-012-0 R1	MOD-032-1, R3	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R3	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators, in conjunction with each of its Transmission Planners, to develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit "at a minimum" requirements.
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators, in conjunction with each of its Transmission Planners, to develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit "at a minimum" requirements. MOD-032-1, Requirement R2 maps to the portion of MOD-013-1, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, R4 to support submission of the data by Planning Coordinators for use in building their respective interconnections. The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an interconnection model is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, R4 to support submission of the data by Planning Coordinators for use in building their respective interconnections. The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an interconnection model is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, R4 to support submission of the data by Planning Coordinators for use in building their respective interconnections. The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an interconnection model is no longer necessary.
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, R4 to support submission of the data by Planning Coordinators for use in building their respective interconnections. The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an interconnection model is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R4	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, part 3.2, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns, meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" In those cases, additional detail regarding the data may be necessary.
NEW	MOD-032-1, R5	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective interconnection-wide models.
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in R1. The Reliability Coordinator may have this data. R2 requires the Reliability Coordinator to supply real time data, if it has the data, to any requesting Planning Coordinator.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-032-1 and MOD-033-1
July 10, 2013

Introduction
The NERC Compliance department (Compliance) worked with the MOD B informal ad hoc group (MOD B Group) in a review of pro forma standards MOD-032-1 and MOD-033-1. The purpose of the review is to discuss the requirements of the pro forma standards to obtain an understanding of their intended purposes and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the MOD B Group and Compliance in order to aid the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all testing requires levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. However, this document makes no assessment as to the enforceability of the standard. The following questions should both assist the MOD B Group in further refining the standard and serve as a tool to develop auditor training.

MOD-032-1 Questions

Question 1
Per MOD-032-1 Requirement R3, will the auditor verify only that the data was delivered as specified, or will the auditor make a determination regarding whether the quality of the data is sufficient?

Compliance Response to Question 1
Based on the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified. This standard does not specify the criteria around quality, so auditors will not make any assessments in that regard.

Question 2
Per MOD-033-1 Requirement R1, is it clear what is meant by “unexplained” or “too large?”

Compliance Response to Question 2
Based on the language in the requirement and the purpose of the standard, which is to implement a process to validate data, the auditor will verify that the documented process includes a criteria discussion about how the entity will make a determination of “unexplained” or “too large.” Auditors will not assess the quality of the entity’s determination, just that the validation process has been implemented and followed.

Conclusion

In general, Compliance finds the pro forma standard provides a reasonable level of guidance for Compliance Auditors to conduct audits in a consistant manner. The standard establishes timelines, data requirements, and ownership of specific actions. Further, the standard provides reasonable guidance to develop training for Compliance Auditors to execute their reviews. However, Compliance does recommend the MOD B Group address the items noted in the response to the question, if applicable.

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the versions of the pro forma standards requirements referenced in this document.

Attachment A

MOD-032-1 Requirements and Measures

R1. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area, including: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Specification of the required data that includes, at a minimum, the data listed in Attachment 1;

1.2. Specification of the data format;

1.3. Specification that the data must be shareable on an interconnection-basis to support use in the interconnection models;

1.4. Specification of the level of detail to which equipment shall be modeled;

1.5. Specification of the case types or scenarios to be modeled; and

1.6. A schedule for submission or confirmation of data at least once every 13 calendar months.

M1. Examples of evidence include, but are not limited to, dated documentation or records that the required modeling data requirements and reporting procedures meet the specifications in Requirement R1.

R2. Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Planning Coordinator shall provide evidence, such as email notices or postal receipts showing recipient and date, that it has distributed the requested data requirements and reporting procedures within 30 days of a written request in accordance with Requirement R2; or a statement by the Planning Coordinator that it has not received a request for its data requirements and reporting procedures.

R3. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Examples of evidence include, but are not limited to, dated documentation or records of submission by a registered entity of the required data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R4. Upon delivery of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R3, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

4.2. If requested by the notifying Planning Coordinator or Transmission Planner, provide additional dynamics data describing the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables; and

4.3. Provide the response within 30 calendar days, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M4. Examples of evidence include, but are not limited to: dated records of a written request from the Transmission Planner or Planning Coordinator notifying a Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider regarding technical concerns, and additional evidence demonstrating the response to the request meets the specifications of Requirement R4; or a statement by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider that it has not received notification regarding usability or technical concerns.

R5. Each Planning Coordinator must submit the data provided under Requirement R3 to the ERO or its designee to support creation of the interconnection model(s) that includes the Planning Coordinator's planning area as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. In the format and according to the schedule specified by the ERO or its designee; and

5.2. Include documentation and reasons for data modifications, if any.

M5. Examples of evidence may include, but are not limited to, dated documentation or records indicating data submission from the Planning Coordinator to the ERO or its designee according to Requirement R5.

MOD-033-1 Requirements and Measures

R1. Each Planning Coordinator must implement a documented process to validate the data used for steady state and dynamic analyses (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses that includes, at a minimum, the following items: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Validate its portion of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other Real-time data sources to check for discrepancies that the Planning Coordinator determines are large or unexplained at least once every 24 calendar months through simulation.

1.2. Validate its portion of the system in the dynamic models at least once every 24 calendar months through simulation of a dynamic local event, unless the time between dynamic local events exceeds 24 calendar months. If the time between dynamic local events exceeds 24 calendar months, validate its portion of the system in the dynamic models through simulation of the next dynamic local event. Complete the simulation within 12 calendar months of the local event.

1.3. Coordinate with the data owner(s) to confirm or correct the model for accuracy when the discrepancy between actual system response and expected system performance is too large, as determined by the Planning Coordinator.

M1. Examples of evidence may include, but are not limited to, a documented validation process and evidence that demonstrates the implementation of the required components of the process.

M2. Each Reliability Coordinator 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 that the Planning Coordinator requests to perform validation under Requirement 1 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]*

R2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

Proposed Timeline for the Project 2010-03 Standard Drafting Team (SDT)		
Anticipated Date	**Location**	**Event**
July 2013	-	SC Authorizes SAR and Pro-forma Standards for Posting
July 2013		Conduct Nominations for Project 2010-03 SDT
July 2013	-	Post SAR and Pro-forma Standards for 45-Day Comment Period
August 2013	-	Conduct Ballot
September 2013	-	45-Day Comment Period and Ballot Closes
September 2013	TBD	MOD B Standard Drafting Team Face to Face Meeting to Respond to Respond to Initial Comments and Revise as Necessary
September 2013	-	Conduct Final Ballot
November 7, 2013	-	NERC Board of Trustees Adoption
December 31, 2013	-	NERC Files Petition with the Applicable Governmental Authorities

Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 & MOD-033-1

Ballot and Non-Binding Poll now open through September 4, 2013

Now Available

A ballot for **MOD-032-1 and MOD-033-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is open through **8 p.m. Eastern on Wednesday, September 4, 2013.**

Background information for this project, can be found on the project page.

Instructions
Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's announcement regarding the balloting software updates and the guidance document, which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard(s). If the comments do not show the need for significant revisions, the standard(s) will proceed to a final ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 & MOD-033-1

Comment Period: July 22, 2013 – September 4, 2013
Ballot Pools Forming Now: July 22, 2013 – August 20, 2013

Upcoming:
Ballots and Non-Binding Polls: August 26, 2013 – September 4, 2013

Now Available

A 45-day formal comment period for **MOD-032-1 and MOD-033-1** is open through **8 p.m. Eastern on Wednesday, September 4, 2013.** The standard authorization request (SAR) for this project is also posted for comment. Additional supporting documents are posted for information. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Tuesday, August 20, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

NERC Reliability Standards MOD-010 through MOD-015 address modeling data requirements that support the mathematical model representations of transmission, generation, and load that are the foundation of virtually all power system studies. Only two of those standards were approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Order No. 693. Four of them were neither approved nor remanded, and they remain in a pending status.

NERC initiated an informal development process ("MOD B") to address the remaining directives related to the existing standards from FERC Order Nos. 890 and 693. Resulting from informal development, two new reliability standards are proposed to replace MOD-010 through MOD-015. The proposal includes a combined modeling data standard, MOD-032-1, and a new validation standard to address directives related to validation, MOD-033-1.

In preparing proposals to address the outstanding directives and proposed improvements to MOD-010 through MOD-015, the ad hoc group ensured that the requirements in the proposals were results-based and considered criteria from the Paragraph 81 project (Project 2013-02 Paragraph 81). The requirements in these standards do not fall under Paragraph 81 criteria because this modeling data has a reliability purpose. Specifically, absence of modeling data for use in the Interconnection models would be expected to have a reliability impact, and the requirements establish consistent modeling data requirements and reporting procedures to support analysis of the reliability of the interconnected transmission system.

The proposed standards are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires a minimum level of data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection model building process in their Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

Background information, including other supporting documents for this project, can be found on the project page. Please contact either Steven Noess, the standards developer or a participant on the informal development group if you would like additional information.

Instructions for Joining Ballot Pool(s)

Ballot pools are being formed for the standards mentioned and the associated non-binding poll in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submit an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Ballot for MOD-032-1 & MOD-033-1: bp-2010-03_MOD_B_in@nerc.com
Non-Binding poll for MOD-032-1 & MOD-033-1: bp-2010-03_MOD_B_NB_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, September 4, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

Ballots for the standards and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Standard Drafting Team Nominations

Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1
Project 2010-04 Demand Data: MOD-031-1
Project 2013-04 Voltage and Reactive Control: VAR-001-3, VAR-002-4
Project 2010-01 Training: PER-005-2

Nomination Period Open: July 24, 2013 – August 2, 2013

Link to Official Nomination Form
Link to Word Version of Nomination Form

Background
These projects have recently transitioned from informal development to formal development. Ad hoc groups developed Standard Authorization Requests, pro-forma Reliability Standards, a technical white paper and supporting documents through the stakeholder consensus building informal development process which are currently posted for comment with upcoming ballots. The NERC Standards Committee is seeking industry experts to serve on standard drafting teams for formal development.

Each standard drafting team (SDT) is proposed to consist of a maximum of 10 members. SDT members are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings (projected to be 3 days a month) as well as participate in all the SDT meetings held via conference calls (projected to be 2 to 5 days a month) for the remainder of 2013. Nominees are asked to be mindful of the time commitment this project will require, and volunteer only if their schedule will allow them to actively participate.

Background information about each project including the projected schedule is available on the project pages. The stakeholders who comprised the ad hoc group participants can be found at the links below:

- Project 2010-03 Modeling Data
- Project 2010-04 Demand Data
- Project 2013-04 Voltage and Reactive Control
- Project 2010-01 Training

Notice to all ad hoc group participants: if you are interested in continuing on the SDT you must nominate yourself to be considered for possible inclusion on the team.

For all projects below, the following are beneficial, but not required: team members with experience in compliance, legal, regulatory, facilitation, technical writing, previous drafting team experience, or experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process. Any person interested in being chair of a SDT must be willing to undergo one half day of facilitation training prior to the first team meeting.

Further, nominees should have technical expertise in the subject matter of the standard drafting team on which they wish to serve, as identified below:

- Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1 – Nominees should have experience in one or more of the following areas: transmission planning, steady-state and dynamics modeling, and system model validation. The project is also seeking perspectives from each Interconnection and from various organizations whose functions are contemplated to be subject to the Reliability Standards.
- Project 2010-04 Demand Data: MOD-031-1 – Nominees should have experience in one or more of the following areas: transmission operations, transmission planning, operations planning, and resource planning.
- Project 2013-04 Voltage and Reactive Control: VAR-001-4, VAR-002-3 – Nominees should have experience in one or more of the following areas: transmission operations, transmission planning, reliability coordination, and generator operation.
- Project 2010-01 Training: PER-005-2 – Nominees should have experience in training or transmission and generation operations.

Instructions for Submitting a Nomination to Participate on a Standard Drafting Team

If you are interested in serving on a SDT, please complete this nomination form by **August 2, 2013**. One nomination form must be submitted for each SDT an individual wishes to volunteer for, describing the individual's experience or qualifications related to that project.

An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our gratitude to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Nomination Form

Standard Drafting Team Members

Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1
Project 2010-04 Demand Data: MOD-031-1
Project 2013-04 Voltage and Reactive Control: VAR-001-3, VAR-002-4
Project 2010-01 Training: PER-005-2

If you are interested in serving on a standard drafting team for one of the projects above, please complete this nomination form by **August 2, 2013**. One nomination form should be submitted for each standard drafting team an individual wishes to volunteer for, describing the individual's experience or qualifications related to that project. If you have any questions, please contact Valerie Agnew at valerie.agnew@nerc.net.

By submitting the following information, you are indicating your willingness and agreement to actively participate in the Standard Drafting Team (SDT) meetings if appointed to the SDT by the Standards Committee. This means that if you are appointed to the SDT, you are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings (projected to be 3 days a month) within the projected schedule as well as participate in all the SDT meetings held via conference calls (projected to be 3-5 days a month) for the durations of 2013. Nominees are asked to be mindful of the time commitment this project will require, and volunteer only if their schedule will allow them to actively participate. The projected schedules can be found on the project pages below.

- Project 2010-03 Modeling Data
- Project 2010-04 Demand Data
- Project 2013-04 Voltage and Reactive Control
- Project 2010-01 Training

Thank you for volunteering! All nominees will be contacted with the disposition of their nomination after the Standards Committee appoints a team for the project for which you have volunteered.

Name:	
Select the Project for which the nominee is volunteering:	☐ Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1 ☐ Project 2010-04 Demand Data: MOD-031-1 ☐ Project 2013-04 Voltage and Reactive Control: VAR-001-3, VAR-002-4

	☐ Project 2010-01 Training: PER-005-2
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the selected Standard Drafting Team:
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR drafting team, standard drafting team, standard review team, or informal ad hoc group. ☐ Currently a member of the following SAR, standard drafting team(s), standard review team(s), or informal ad hoc group:
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team experience. ☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ ERCOT	☐ NPCC	☐ SPP
☐ FRCC	☐ RFC	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:			
☐ Balancing Authority ☐ Compliance Enforcement Authority ☐ Distribution Provider ☐ Generator Operator ☐ Generator Owner ☐ Interchange Authority ☐ Load-serving Entity ☐ Market Operator ☐ Planning Coordinator		☐ Transmission Operator ☐ Transmission Owner ☐ Transmission Planner ☐ Transmission Service Provider ☐ Purchasing-selling Entity ☐ Reliability Coordinator ☐ Reliability Assurer ☐ Resource Planner	
Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name of your immediate supervisor if not provided above:			
Name:		Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

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Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 & MOD-033-1

Ballot and Non-Binding Poll Results

Now Available

A ballot for **MOD-032-1 and MOD-033-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, September 4, 2013.**

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 82.29% Approval: 41.24%	Quorum: 79.66% Supportive Opinions: 40.00%

Background information for this project, can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. The standard will then proceed to an additional comment period and ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2010-03 MOD-032-1 and MOD-033-1 (MOD B)
Ballot Period:	8/26/2013 - 9/4/2013
Ballot Type:	Initial
Total # Votes:	316
Total Ballot Pool:	384
Quorum:	**82.29 % The Quorum has been reached**
Weighted Segment Vote:	41.24 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	31	0.392	48	0.608	1	8	17
2 - Segment 2	9	0.7	2	0.2	5	0.5	0	1	1
3 - Segment 3	84	1	29	0.46	34	0.54	0	7	14
4 - Segment 4	29	1	6	0.273	16	0.727	0	2	5
5 - Segment 5	91	1	18	0.321	38	0.679	0	11	24
6 - Segment 6	51	1	15	0.341	29	0.659	0	2	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	3	0.3	1	0.1	2	0.2	0	0	0
10 - Segment 10	8	0.7	5	0.5	2	0.2	0	0	1
Totals	**384**	**7**	**110**	**2.887**	**174**	**4.113**	**1**	**31**	**68**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	COMMENT RECEIVED
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
				SUPPORTS

1	Associated Electric Cooperative, Inc.	John Bussman	Negative	THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Negative	COMMENT RECEIVED
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
1	Colorado Springs Utilities	Paul Morland	Negative	COMMENT RECEIVED
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	NO COMMENT RECEIVED - (Dominion)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - NIPSCO(MISO) - (MISO)
1	JEA	Ted Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Lincoln Electric System	Doug Bantam	Negative	COMMENT RECEIVED
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO-NSRF)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lynn Schmidt, NIPSCO)
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	

1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams	Negative	COMMENT RECEIVED
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eleanor Ewry of Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	San Diego Gas & Electric	Will Speer	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED

1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC & NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	Central Lincoln PUD	Steve Alexanderson	Negative	COMMENT RECEIVED
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Clewiston	Lynne Mila		
3	City of Redding	Bill Hughes	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED

3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Negative	COMMENT RECEIVED
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum (NSRF))
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lynn Schmidt, NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	

3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Negative	COMMENT RECEIVED
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole comments)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	COMMENT RECEIVED
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy Comments)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (support the comments of Floriday Municipal Power Agency (FMPA))
4	Central Lincoln PUD	Shamus J Gamache	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson for the Western Small Entity Comment Group.)

4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, Florida Municipal Power Agency)
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (The separate comments of both SEC and FMPA)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
				SUPPORTS

5	Amerenue	Sam Dwyer	Negative	THIRD PARTY COMMENTS - (Ameren)
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	COMMENT RECEIVED
5	City of Redding	Paul A. Cummings	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Abstain	
5	Detroit Edison Company	Alexander Eizans	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA or(Kathleen Black) - (Kathleen Black)
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO, NSRF, and ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED

5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	COMMENT RECEIVED
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
5	Omaha Public Power District	Mahmood Z. Safi		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Raven Power	Scott A Etnoyer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
				SUPPORTS

5	Salt River Project	William Alkema	Negative	THIRD PARTY COMMENTS - (SRP)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Western Area Power Administration)
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	City of Redding	Marvin Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (First Energy)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF / ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant / Luminant Power)
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney at FMPA)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lynn Schmidt NIPSCO)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED

6	Salt River Project	Steven J Hulet	Negative	COMMENT RECEIVED
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	COMMENT RECEIVED
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Steve Alexanderson for the Western Small Entity Comment Group)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	COMMENT RECEIVED
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Negative	COMMENT RECEIVED
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Planning Standards Subcommittee - Jim Kelley 9/3/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-binding Poll

Project 2010-03 MOD B

Non-binding Results	
Non-binding Poll Name:	Project 2010-03 MOD-032-1 and MOD-033-1 (MOD B) Non-binding Poll_1_in
Poll Period:	8/26/2013 - 9/4/2013
Total # Votes:	278
Total Ballot Pool:	349
Summary Results:	79.66% of those who registered to participate provided an opinion or an abstention; 40.00% of those who provided a opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Negative	COMMENT RECEIVED
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Negative	COMMENT RECEIVED
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy		

1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	COMMENT RECEIVED
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - NIPSCO - (MISO)
1	JEA	Ted Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Lincoln Electric System	Doug Bantam	Negative	COMMENT RECEIVED
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lynn Schmidt, NIPSCO)
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Eleanor Ewry of Puget Sound Energy)
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Negative	COMMENT RECEIVED
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	

1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Clewiston	Lynne Mila		
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	

3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Negative	COMMENT RECEIVED
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lynn Schmidt, NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	

3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	COMMENT RECEIVED
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Negative	COMMENT RECEIVED
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	COMMENT RECEIVED
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (support the comments of Florida Municipal Power Agency (FMPA))
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Abstain	
5	BC Hydro and Power Authority	Clement Ma		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	COMMENT RECEIVED
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Abstain	
5	Detroit Edison Company	Alexander Eizans	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA(Kathleen Black) - (Kathleen Black)
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	

5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO, NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Abstain	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough		
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	COMMENT RECEIVED
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
5	Omaha Public Power District	Mahmood Z. Safi		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		

5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Raven Power	Scott A Etnoyer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRP)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Abstain	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Western Area Power Administration)
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (First Energy)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra Energy)

6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF / ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney at FMPA)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lynn Schmidt NISPCO)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	Steven J Hulet	Negative	COMMENT RECEIVED
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	

8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Planning Standards Subcommittee - Jim Kelley 9/3/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (72 Responses)
Name (45 Responses)
Organization (45 Responses)
Group Name (27 Responses)
Lead Contact (27 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 (72 Responses)
Question 1 (58 Responses)
Question 1 Comments (67 Responses)
Question 2 (60 Responses)
Question 2 Comments (67 Responses)
Question 3 (0 Responses)
Question 3 Comments (67 Responses)
Question 4 (54 Responses)
Question 4 Comments (67 Responses)
Question 4 (0 Responses)
Question 5 Comments (67 Responses)

Group
Western Small Entity Comment Group
Steve Alexanderson
Yes
According to the SAR, “All devices and equipment attached to the electric grid must be modeled to accurately capture how that equipment performs under static and dynamic conditions.” The comment group finds this statement to be absolute and overly inclusive. We don’t believe that every 25 W lamp can or should be modeled. We suggest that there should be a qualifying statement limiting this Project to BES Facilities and Elements, or something with these limits.
Yes
1)Attachment 1 Item 1 under the steady-state header asks for the Aggregate Demand at each Load Serving Entity bus as a minimum. Since “bus” is not a NERC defined term, we looked at the IEEE dictionary and found the most appropriate definition is “A conductor, or group of conductors, that serves as a common connection for two or more circuits.” By this definition, we see that Load Serving Entities will be asked to report demand data for many hundreds of thousands of buses, the vast majority of them at service-level voltages. Per R1.1, the PC will not have the authority to reduce this minimum number of buses to a more reasonable number. We can’t imagine the SDT is considering this degree of modeling, and suggest that some bounds be put around the “each bus” requirement. We suggest: “2. Aggregate Demand at each Bulk Electric System bus [LSE].” Another solution would be to add an applicable facility section as other recent standard projects are doing. 2)The comment group is unsure what is meant by Item 5 under the dynamic header of Attachment 1. The requirement does not specify whether the Demand data sought is entity wide, by bus, by metering point, etc…
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
Central Lincoln
Group
Northeast Power Coordinating council

Guy Zito
Yes
The SAR should not be posted with the Standard. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard's development or revision. Posting the Standard for comments and ballot means that the SAR is "water under the bridge", and that industry's input on the SAR doesn't mean anything. We support combining Standards MOD-010 through MOD-015 into fewer standards. Suggest revising SAR Information Section Item 3a. to: Identify responsibility to provide and who receives the data.
Yes
The format of part 1.2 should be is accepted to be used in the industry (i.e. what is already in use). The R1.6 stipluated 13 month schedule is odd. Explain the rationale or change to 12 or 15 months. R2 must consider communication when any change occurs. Suggest revising to: …within 30 days of developing any changes or following a written request… Part 4.2 refers to dynamics data. It should be part of R1 and Attachment 1. Part 1.5 is unclear and it's purpose is unknown. The use of the term "case type" is confusing as these are already specified as steady state, short circuit, and dynamics. Part 1.5 also states that the scenarios to be modeled should be included. These models should be able to be used for numerous different testing scenarios in the future, and there is no need to specify those scenarios as part of data collection. A part 1.7 should be included that would read: 1.7 No "Black Box" models shall be permitted without a complete description including operational description of inputs to the model. In Requirement part 1.1 remove the term "at a minimum" and change the part to read "Specification of the required data per information listed in Attachment 1;" In Attachment 1 add to Item 9 in the table the following statement "Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. (BA, GO, LSE, TO, TSP)" to the Dynamics and the Short Circuit columns. TPL-001-4 refers to MOD-010 and MOD-012. This will need to be modified or preferably cross reference to other standards should be eliminated to avoid this problem. Regarding R2, this requirement is unclear on the requesting part. Requirement R1 assigns the Planning Coordinator (in conjunction with its Transmission Planner) the responsibility to develop steady-state, dynamics, and short circuit modeling data requirements "within 30 calendar days of a written request for the data requirements and reporting procedures". The PC is the entity having a need and therefore will make a request for submission of data by the entities listed in R2 (BA, GO, LSE, RP, TO and TSP) in accordance with the procedures for data reporting. It is unclear as to who issues "a written request" for the data requirements and reporting procedures. Is it the entities listed in R2 themselves, or other entities not listed, or the PC itself? R2 is unclear on what request it is, and who makes the request. Measure M2 seems to suggest that it is the PC who receives such a request. That being the case, the question becomes who issues the request, and the reason for the request. Regarding R3, the sentence "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." should be deleted since it is not a requirement. It is a measure of compliance, which is already adequately captured in Measure M3. Regarding R4, the phrase "including the technical basis or reason for the technical concerns," implies that the PC is required to provide this in the written notification, but there is no such requirement stipulated anywhere. If this is not a requirement, then it does not add any value to Requirement R4 as this requirement stipulates the tasks required of the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider upon receiving a notification from the PC/TP. Part 4.2 is out of place and should be removed. As presented, part 4.1 projects a separate requirement for dynamics data describing the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables which should have been (and most appropriately) included in R1 and Attachment 1. To address the intent of part 4.2 thus allowing for the situation that a PC or TP may request additional data in its notification, we suggest the following wording change to R4. The change reflects conformance to NERC Standard requirement format, and it should be made into two Requirements: Each Planning Coordinator or Transmission Planner shall deliver written notification of technical concerns with the data submitted under Requirement R3 or convey the need for additional data. Each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: 4.1 The proposed 4.1 4.2 The proposed 4.3, assuming 4.2 will be

removed as suggested Regarding the VSL for R2, the condition before the “or” may render a Responsible Entity being assigned a Severe VSL if it fails to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days but short of exceeding the 75 days. Suggest this VSL be revised to: The Planning Coordinator did not provide its data requirements and reporting procedures according to Requirement R2, OR The Planning Coordinator provided its data requirements and reporting procedures according to Requirement R2 greater than 75 calendar days after a written request.
No
Requirement R1 should not make reference to a non-existent standard. Part 1.2 can be condensed to: 1.2 Validate its portion of the system in the dynamic models through simulation of dynamic local events. If within any period of 24 months more than one event may have occurs, only one validation is required for the 24 month period. In part 1.2, add a description or definition of the term “Dynamic Local Events”. Regarding R1, “must” with “shall” to be consistent with other standards. Regarding the VSL for R1, the second condition under Low VSL needs to be qualified so that the situation only applies when the time between the previous dynamic local event and the events that occurred that required a simulation within 12 months exceeded 24 calendar months. Regarding the VSLs for R2, all instances of “planning coordinator” should be capitalized. An acceptable validation generally comprises comparing data available in EMS with simulation predictions produced by planning models. Our past experience is validation is less challenging for steady-state comparison, but quite a challenge in validating dynamic performance due to EMS or off-line models do not sufficiently represent all impactful activities of power plants or devices, and equipment owners are not supportive to ensure models are current and adequate. As written, the Standard is applicable strictly to Planning Coordinators. Equipment owners are not partners of validation. Unless the language of the Standard places sufficient responsibility on equipment owners to check models for their own equipment frequently, and share accurate current operating information, the success will be limited. We suggest the Drafting Team expand this Standard to address this concern or otherwise to enable Planning Coordinators to meet their obligations stipulated in the Standard. If the EMS data and planning model responses are significantly different, either models may contain misrepresentations or bad data, or some actual activities are not modeled. The Standard should stipulate accountability on equipment owners to report or assist identifying changes to operating settings (which are unavailable in EMS) that affect models or operating practices not modeled. Failed validation should include a greater degree of accountability to equipment owners.
Individual
Thomas Foltz
American Electric Power
No
Yes
AEP recommends that team provide clarification with respect to the functional entities listed within the table for Attachment 1. For example, in state-state item number 2, it lists the LSE as the functional entity. Does this depect the likely source to provide the information or is this the only entity that will be asked and be required to provide this information? AEP prefers flexibility within this approach as RTO practices might vary in how they collect this information.
Yes
Individual
John Gross
Avista
No

Yes
1. Requiremt R5.2 is unclear with the term "data modifications." Removing R5.2 and consolidating R5.1 into R5 would still meet the objective of requiring the PC to sumbit data to the ERO. 2. Historically the industry has seperated transmission system modeling data into categories such as what was done in Attachment 1: steady-state, dynamics, and short circuit. The drafting team can consider consolidating the three columns therefore stating all necessary modeling data for a specific item in a single location. Example: AC Transmission Line or Circuit requires i. impedance (all sequences and mutuals), ii. ratings, iii. status. 3. The drafting teams should provide guidance on how the PC should handle Generating Units with capacity limits below the NERC functional entity registration limits. Generators below the 20 MVA single unit and 75 MVA plant are still desired to be modeled both in the interconnection wide model and PC level models. 4. The assignment of functional entities in Attachment 1 may not be sufficient. A bus, for example, may be owned by a GO therefore designating only TO as being responsible could leave a gap. The drafting team can consider the approach used by the WECC-0074 drafting team in developing MOD-11 and 13-WECC-CRT-1. Stating each TO of transmission facilities represented and each GO of generation facility represented. 5. The item Each Bus in Attachement 1 should include requirements for lat, long location and substation. 6. The drafting team should provide an acceptable threshold of station service auxiliary load required to be modeled as stated under Generating Units of Attachment 1. WECC has established a threshold of 1 MW or greater to be explicity modeled. 7. Attachment 1 should include the item "Substation" requiring lat, long location and grounding impedance. Providing this additional data will aid in addressing the geomagnetic induced currents study requirements. 8. The drafting team should consider aligning data requirements in MOD-025-2 with the generator real and reactive power capabilities required in Attachment 1.
Yes
Requirement R1 should be split into two seperate requirements stating (1) the requirement to have a documented process and (2) a requirement to implement the process.
Individual
Lynn Schmidt
NIPSCO
No
Yes
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 RRO/RFC, to the planning coordinator, MISO. For NIPSCO, developing accurate and usable models requires close coordination with the two large neighboring interconnected utilities having the greatest impact on NIPSCO, Commonwealth Edison and AEP. NIPSCO, CE, and AEP are all in the same regional reliability organization, 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. Also, MISO has sometimes struggled in their model building efforts. In the 2000's, MISO promoted their Model-On-Demand (MOD) software, which would create future powerflow models by "pushbutton" and which companies would use to submit their NERC MMWG modeling requirements. While Model-On-Demand still survives, neither of these two goals has been achieved and there have been no discernible improvements. RFC has a much more sustained and proven track record of

proficient model building coordination. If one of the rationales for MOD-032 is to produce better system models, the results will be the exact opposite. 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.
Yes
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.
Individual
Kathleen Goodman
ISO New England, Inc.
No
Yes
Under R1 - Requirement R1.5 is unclear and it’s purpose is unknown. The use of the term “case type” is confusing as these are already specified as steady state, short circuit, and dynamics. R1.5 also states that the scenarios to be modeled should be included. These models should be able to be used for numerous different testing scenarios in the future, and there is no need to specify those scenarios as part of data collection. A requirement 1.7 should be included: 1.7 No “Black Box” models shall be permitted without a complete description including operational description of inputs to the model.
Yes
Individual
Martyn Turner
LCRA Transmission Services Corporation
No
Yes
To address existing entity NERC registration in the ERCOT region, “Planning Coordinator” should be replaced with “Planning Authority and /or Reliability Coordinator”. This is shown below for the introductory paragraph (R1) but would apply to the other requirements and sub-requirements as well. Also, the requirements for the Transmission Planner are not clearly specified and LCRA TSC recommends that this requirement only apply to the PA and /or RC. R1. Each Planning Authority and /or Reliability Coordinator shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area, including: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] In Attachment A, a footnote should be added to the short circuit section of the table: * Positive sequence data may be substituted for negative sequence data where appropriate.

Yes
To address existing entity NERC registration in the ERCOT region, LCRA TSC recommends replacing “Planning Coordinator” with “Planning Authority and /or Reliability Coordinator”. This is shown below for the introductory paragraph (R1) but would apply to the other requirements and sub-requirements as well. Short circuit modeling data was clearly specified in the proposed MOD-032-1; however, the requirement to validate short circuit modeling data is not considered in the proposed MOD-033-1. For consistency and completeness, LCRA TSC recommends adding a requirement to validate short circuit data and modeling similar to the requirements proposed for steady state and dynamics. LCRA TSC believes requirement R1.3 is redundant as it is already covered in requirements of the proposed MOD-032-1. LCRA TSC recommends deleting requirements R1.3. In R2, LCRA TSC believes the Transmission Owner, as the asset owner, should be responsible for providing actual system behavior data. The reporting of data and modeling validation efforts is not presently part of the requirements in MOD-033-1. LCRA TSC recommends adding a requirement for the Planning Authority and /or Reliability Coordinator to report on validation results. R1. Each Planning Authority and /or Reliability Coordinator must implement a documented process to validate the data used for steady state, short circuit, and dynamic analyses (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses that includes, at a minimum, the following items: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.3. Validate its portion of the system in the short circuit model by comparing it to actual system behavior to check for discrepancies that the Planning Authority and/or Planning Coordinator determines are large or unexplained at least once every 24 calendar months through simulation. R2. Each Reliability Coordinator and Transmission Owner shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator that the Planning Coordinator requests to perform validation under Requirement 1 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] R3. Each Planning Authority and/or Planning Coordinator must provide a final report summarizing the data validation process, findings, and conclusions.
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
Yes
Clarification is requested on whether TOs would still be responsible for submitting the steady state and dynamic data for GOs since MOD-032 R3 states that “Each BA, GO, LSE, RP, TO, and TSP shall provide steady-state, dynamics, and short circuit modeling data to its TP) and PC according to the data requirements ….” The current process requires the TOs to submit the data on behalf of the GO, which is not practical since the TOs don’t own the GO data. If the process of TOs collecting the GO data and formatting the data remains the same, it is requested that a statement be added to the standard to the effect that the TO will not be violation of the requirement if the GO does not provide the data to the TO or if the GO does not provide the data in the required format and the TO makes a mistake in providing the data in the required format.
Group
Arizona Public Service Company
Janet Smith
No

Yes
Yes
Individual
Jonathan Appelbaum
The United Illuminating Company
R1 contains the phrase in conjunction with the Transmisison Planners. We are concerned that this could be interpreted to place an enforceable responsibility on Transmision Planners to participate or seek out to participate. The phrasing does not oblige the PC to listen to the TPL so there is no reason to include the phrase.
1) We are concerned with the word accurate in the purpose statement. Reliaility Standards are read as whole. At times the best data available may not be accurate by definition. 2) We are concerned with what model is being validated against an actual disturbance. There are many models, steady-state, dynamic, short circuit, planning horizon with various scenatios, 7 day operating model, and real-time hourly.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power System Planning comments that system models are the foundation for assessing system reliability and operating the system securely. System models are used to establish Path SOLs, IROLs, mitigation plans, generation interconnection studies and their impact on system performance, etc. Why was such an important standards such as the revised MOD Standards selected for informal development on accelerated schedule? Idaho Power System Planning comments that due to the importance of a MOD standards and the potential impact of not following such standards on system reliability that NERC BOT adoption of the new MOD standards by the end of the year seems like an unreasonable timeline. FERC did not approve several MOD standards in Order 693, due to their "fill-in-the-blank nature" and requirement assignment to the RRO, which is not in the NERC Functional Model; Idaho Power System Planning comments that due to the importance of the impact of MOD standards on reliability objectives, development of the replacement MOD Standards should not be rushed.
Yes
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power does not agree with the approach in MOD-032-1. Since FERC has already refused to approve "fill-in-the-blank" standards where the RRO was responsible for "fillling-in-the-blanks", why does the SDT think FERC will approve more "fill-in-the-blank" standards where each any every Planning Coordinator is "filling-in-the-blanks"? Obligations must be reasonably prescribed within the standard, and not simply "refer" to requirements and obligations to be determined by some other entity. The "fill-in-the-blank" approach is not a reasonable delegation of authority.
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. MOD-032-1 Requirement R1 requires each Planning Coordinator to develop data reporting requirements and procedures for its planning area that includes the attribuites listed in Parts 1.1-1.6. This approach significantly differs from the current processes used by WECC members for interconnection model development, data reporting, and basecase data compliation in that WECC

members are expected to follow the established WECC Regional data reporting procedures and data reporting requirements. In addition, R1-Part 1.5 and 1.6 allows each PC to specify the case types and scenarios and schedule for submission or confirmation of data without a formal review and approval process of interconnection stakeholders or without considering the Reliability Assurer's programmatic needs which are beyond those of the individual Planning Coordinator are; which is also significantly different from the WECC basecase model development process where the WECC SRWG develops the case types and scenarios to be modeled which are then reviewed and approved by WECC TSS prior to basecase creation via a formal review process. WECC and WECC Members have also significantly invested into new software tools known as the Base Case Coordination System that already define the data reporting format data. Submitters will be expected to follow the data reporting format requirements established within the WECC BCCS. WECC committes such as the WECC Planning Coordination Committee, the WECC Technical Studies Subcommittee, the WECC System Review Group and the WECC Model and Validation Working Group have invested considerable time and effort in defining WECC data reporting requirements and processes through the development (and maintenance) of the WECC Data Preparation Manual, the WECC Generator Testing and Model Validation Policy, the MOD-11 and 13-WECC-CRT-1 approved Regional Criteria, and numerous other WECC policies and guidelines. It seems that little reliabilty benefit is gained by requiring each PC to develop data reporting requirements and procedures for its planning area when well established and successful processes, policies, procedures, and data reporting requirements already exist within the WECC Region. It is understood that NERC MOD-011, MOD-013, MOD-014, and MOD-015 list the RRO as the applicable entity and as idenfied in the SAR references to the RRO should be removed for exisitng and new MOD requirements. Idaho Power System Planing agrees that the RRO is not in the NERC funcitonal model and should not be referenced in MOD-032 and MOD-033 requirements. However, the Reliability Assurer (RA) is included in the NERC Functional Model and provides a mechanism to link the well established and successful data reporting procedures and requirements developed and managed within the WECC Region to the expectations listed in MOD-032 Requirement R1 for each NERC Planning Coordinator. Inclusion of the Reliability Assurer as an applicable functional entity and establishment of an additional Requirement or attribuite of Requirement R1 (i.e. Part 1.7) in MOD-032-1 improves the quality and enforceability of the standard if such a requirement also required a PC to establish its modeling data requirements and reporting procedures consistent with the data reporting requirements and procedures of its Reliability Assurer, where an established process exists. For example, under NERC MOD-032 R1 a PC could establish a data reporting procedure that includes all items listed in Requirement R1-Parts 1.1-1.6 but does not include data reporting requirements for UFLS or UVLS dynamics data for inclusion in the interconnection study cases. A TO reporting entity could then report all the data as required under Requirement R3 in accordance with its PC's R1 procedures. In this example, both the PC and TO would be in compliance with NERC MOD-032 requirements but would not meet WECC established data reporting requirements since dynamics data in addition to the items required in NERC MOD-032 Attachment 1 such as UVLS and UFLS data records are required data types per WECC data reporting requirements. This example could be further extended to inclusion of line and transformer relay modeling data in WECC basecases, which are data types WECC is taking steps to require data submitters to include in their data submittals. NERC MOD-032 as drafted does not provide a mechanism to collect such data if a PC chooses to deviate in its R1 procedure from the WECC established regional data reporting requirements captured in existing processes. Adding a requirement in NERC MOD-032 that includes the Reliability Assurer and also requires a PC to establish its R1 model data requirements and reporting procedures consistent with established RA data requirements and reporting procedures strengthens the enforcabilty of the standard and ensures each PC, BA, GO, LSE, RP, TO, TP, TSP is reporting the required modeling data consistent with well establised WECC Regional Requirements. Idaho Power System Planning comments that page 22 of NERC MOD-032 specifically states "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 what is already in place…" Not one of the MOD-032 requirements reference retaining consistency with regionally established processes and procedures, thus MOD-032 does not create a framework to support what is already in place. Inclusion of the RA Functional Entity in the MOD-032 Standard and establishing requirements for a PC to develop its procedures as required by R1 consistent with existing processes and procedures established and maintained by the RA better demonstrates the ideas discussed in the Guidelines and Technical Basis language on page 22. The approach of including the RA in MOD-032 creates a framework to support what is already in place. Ballot Position: Negative with the following comments:

MOD-032-1 would be acceptable to Idaho Power System Planning if the standard were modified to include the Reliability Assurer NERC Functional Entity and add an additional requirement or modify Requirement R1 to require each Planning Coordinator to establish its planning area modeling data and reporting requirements consistent with the modeling data and data reporting requirements of its RA if such requirements are established within its interconnection region (especially for the WECC Regional Entities). Standards should be drafted with clear goals in mind and a way to make those goals achieveable and measureable. This standard does neither, as it tell the Planning Coordinator to develop it's own requirements and procedures. Standards are to help the industry standardize and make the system more reliable. This is the wrong approach.
Yes
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power System Planning agrees with the approach in MOD-033-1.
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power System Planning agrees with the approach in MOD-033-1. While Requirement R1 Item 1.3 addresses FERC Order 890, paragraph 290 and FERC Order 693, paragraphs 1211 and 1220 directives, in that system models should be modified and updated to improve their accuracy when validation assessments identify unacceptable model accuracy concerns; R1 Part 1.3 does not provide a timing requirement that holds a Planning Coordinator accountable for correcting the model accuracy when a discrepency it identified. Idaho Power System Planning comments that R1-Part 1.3 should be modified to include a time requirement for correcting the model deficiency within six calendar months of determining such discrepency. MOD-032-1 Requirement R4 provides a mechanism for a PC to collect corrected data from data owner(s) in a timely manner; similarly MOD-033-1 Requirement R1-Part 1.3 should establish a time requirement for Planning Coordinators to implement model corrections. Ballot Position: Negative with the following comments: MOD-033-1 would be acceptable to Idaho Power System Planning if Requirement R1-Part 1.3 was modified to include a time requirement that holds Planning Coordinators accountable for implementing model corrections. A six month timeframe seems reasonable for such a requirement.
Group
Luminant
Rick Terrill
No
Yes
Luminant appreciates the work of the Ad Hoc team and generally agrees that the data modeling requirements are appropriate. Luminant is voting negative due to a moderate concern: The Planning Coordinator develops the details data specifications and reporting requirements, including the timelines for reporting. Modeling methods change over time, as could data needs. In MOD-032, R3 or R4, the SDT should address the issue of data requests where the requested data may not be readily available. This could be easily addressed by a technical basis documentation similar to that noted in R4.
Luminant appreciates the work of the Ad Hoc team and generally agrees that the data modeling requirements are appropriate. Luminant is voting negative due to a moderate concern: The Planning Coordinator develops the details data specifications and reporting requirements, including the timelines for reporting. Modeling methods change over time, as could data needs. In MOD-032, R3 or R4, the SDT should address the issue of data requests where the requested data may not be readily available. This could be easily addressed by a technical basis documentation similar to that noted in R4.
Group
BC Hydro and Power Authority
Patricia Robertson

No
BC Hydro supports the consolidation of the MOD standards. However BC Hydro has voted Negative as BC Hydro has concerns with assigning the responsibility of the modelling development framework and validation to the Planning Coordinator (PC). Currently, the RRO (WECC for our region) is developing data requirements and reporting procedures to have consistency (technical details to form adequate base cases) across the region. If the standard assigned the modelling data requirements and reporting procedures to the RRO instead of the PC , then coordination for the ERO (NERC) interconnection models would occur among 8 RRO's as opposed to 80 PCs (currently 80 entities are registered as PCs according to NERC's site. WECC is also currently developing guidance for model validations (including frequency) for its region and BC Hydro believes this is the appropriate level (ie at the RRO level) to ensure consistency. In summary, the RRO's have the resources, including drafting committees, working groups and task forces to develop the modelling data requirements, reporting procedures and model validation to create adequate and consistent interconnection models for the ERO.
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Individual

David Wang
SDG&E
No
San Diego Gas & Electric (SDG&E) recommends a negative vote on NERC Project 2010-03: Modeling Data (MOD B), which proposes Reliability Standards MOD-032-1 and MOD-033-1, for the following reasons. First, while MOD-032-1 consolidates the concepts from the original data requirements of MOD-011-0 and MOD-013-0, it also includes a new requirement to account for the collection of short-circuit data. SDG&E does not believe that it is necessary for the Planning Coordinator to receive short-circuit data to effectively model the interconnected transmission system because short-circuit data is really only useful at the local level, and in most cases does not relate to system-wide interconnections. Secondly, the results of analyzing this data are already available in two places - as part of the annual FERC Form 715 filing, which provides a summary of all Transmission Planning activity for the prior calendar year as well as in the annual Grid Assessment Study Report. Finally, unlike steady-state and dynamics data, short circuit data is only accessible through use of the ASPEN program, which would have to be purchased and is quite costly. Should the short-circuit data collection requirement unfortunately remain in the Standard, its submission should only be required, at a maximum, once every 13 calendar months per sub-requirement R1.6. SDG&E also takes issue with MOD-033-1, which requires the Planning Coordinator to validate data for steady state and dynamics models within its area through simulation of a dynamic local event. SDG&E does not believe this requirement is necessary, given that load flow data is updated constantly, and any new data, including changes to the system, is incorporated into subsequent case submissions. Lastly, case validation has taken place previously due to special case requests from WECC, which required a case to be made from data at a given point in time. To SDG&E's knowledge, there were no major discrepancies between the requested point-in-time case and actual data values that were used to validate the requested case. As such, data validation cases have been requested in the past and no significant issues have appeared.
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Individual
John Bee
Exelon and its' Affiliates

Yes
The steady-state and dynamic data previously covered by MOD-010 through MOD-013 can be considered system-wide data, while short-circuit modeling is more of a local issue. The inclusion of the short-circuit data in the new standard unnecessarily complicates the process. While the move toward reducing the number of standards is positive development, going too far can complicate data collection and compliance unnecessarily. The short-circuit data requirements should be a separate standard.
Yes
In requirement R1 of MOD-031, the RRO is to work with the TOs, TPs, GOs, and RPs to develop requirements and reporting procedures. In R1 of MOD-032-1, this language has been modified to only specify the transmission planners. Is this change intentional? Many large transmission owners are no longer transmission planners in the eyes of NERC. Transmission Owners who are not also Transmission Planners have driven many of the improvements in the MOD-010 and MOD-012 reporting processes. It appears from R1 that the TOs would no longer be responsible for collecting generator data from the GOs unless this is made an assigned task by the TP. Is this interpretation correct? The requirement for short-circuit data will involve combining data from software such as PSS/E, CAPE, and ASPEN. Data interchange between applications is not always well supported and may involve the loss of some data. Does NERC plan to work with the software vendors to simplify this process, or is the process more likely to be settling on a least common denominator? Requirment R4.3 suggest that 4.3 below should be at least 60 days not 30 days. Typically we may have to go back to a vendor for this information and 30 days may be problematic in getting the information.
Yes
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Frank Gaffney, Florida Municipal Power Agency
Individual
John Seelke
Public Service Enterprise Group
Yes
a. Specific FERC directives that are being addressed by this project are not identified. MOD-032-1 and MOD-033-1 (p.1 of each) merely state “Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015.” The individual directives should be clearly identified in the SAR. b. The SAR should address how data for planned facilities (as opposed to existing facilities) is intended to be provided. (MOD-032-1 – Attachments 1 addresses this superficially.) Entities that are planning new facilities are subject to reliability assessments under FAC-002-1. Assessments are conducted by the “Transmission Planner and Planning Authority” in accordance with R1 of FAC-002-1, and they would have the data for new facilities. However, including that data into planning models has several issues that the SAR does not address. One issue is data confidentiality, which is discussed in item 1.c below and which applies to data for existing facilities. The second issue is determining the planned facilities for which data should be requested. Many generation and transmission projects will be competitive projects, and all of them will not be needed. The entities developing those projects would need to provide their permission to allow the data that they have provided to the PC or TP under FAC-002-1 to be used for MOD-032-1, provided that the data to be used for modeling is limited to that which they have provided under FAC-002-1 and no more. Eventually, model builders may select future projects for their models. c. Data confidentiality is a major issue which the SAR has not addressed adequately. Data may be confidential for a number or reasons, but the two greatest are (1) it is CEII and (2) it is commercially sensitive. The issue is briefly

discussed in the SAR on p. 8 in setion 3.e “Sharability (an issue tangential to the MOD standards).” The SAR should require the the drafting team develop solutions to the problems identified in SAR section 3e. Specifically, it should require that the team address (1) what entities will have access to which confidential data and (b) what provision will be required for such access to ensure that confidentiality is maintained. That should be a requirement in the SAR. The two comments below are related to “data confidentiality.” i. Data may be needed by other that a PC of a TP. TOs and GOs may need short circuit data for protection system coordination. TOPs may need existing data to validate their databases. ii. In MOD-032-1, R1 subpart1.3 does not address shareability adequately. First, it leaves the parameters of “shareability” up to each PC’s procedure, a non-starter if the data is to be shareable on an Interconnection-wide basis. We will provide further comments on R1 in response to the question #3 on MOD-032-1.
No
We recommend that the team explain why it did not elect pursue a Section 1600 data request as opposed to a standard. A Section 1600 data equest would require that specific data be requested in a particular format. It would require that data confidentiality be addressed. It would allow for additional data to be added or deleted in a process that is considerably shorted than changing a standard.
a. The standard has failed to address the concerns identified in the existing SAR regarding standard format in section 3.c on p. 7 and data confidentiality (i.e., sharing) from section 3.e on p. 8. i. R1 allows each PC to specify (1) the data it will request, and (2) the data format, including the level of detail, and (3) that shareability is required without addressing how data confidentiality will be addressed. R1 needs common NERC-wide solutions, not PC-specified solutions. i. In addition, we do not see understand why subpart 1.5 (case types and scenarios to be modeled) is contained in a data request that data providing entities must submit in R3. The data requested should be sufficient to address whatever the model builders need. In other words, how is this a concern of the data providers? ii. We object to subpart 1.1 that allows each PC or TP to specify data “that includes, at a minimum, the data listed in Attachment 1.” Attachment 1 imposes data reporting obligations on numerous entites other that a PC or TP - see section 4.1 of MOD-031-1. Therefore, the phrase “at a minimum” sets no limit on what can be requested and subequently provided by data owners for compliance with MOD-031-1. This language is a “fill-in-the-blank” requirement and therefore unacceptible. b. Regarding Attachment 1: i. We do not understand what “share of reactive contribution for voltage regulation” which is designated for items 3, 7, and 8 means. ii. Item #9 is objectionable for the reasons described the our response in 3.a.ii above. iii. Other standards require generator data to be provided to the PC or TP such as the four standards in Project 2007-09 Generator Verification (PRC-019-1 – Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection, PRC-024-1 – Generator Performance During Frequency and Voltage Excursions, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and MOD-027 -1 – Verification of Generator Unit Frequency Response. If a PC asks for the same data in MOD-032-1 as is required by these standards, a Registered Entity could face double compliance jeopardy, which is unacceptable. c. Regarding R3, two entities are designated to receive data (the PC and the TP). This will create a burden and a compliance issue. The PC should be designated to receive the and entity’s data. d. Regarding R4, two enity’s (the PC or the TP) may request clatification on the data submitted. This again should be restricted to one entity as designated by the PC. Otherwise, a data providers may receive multiple requests. In addition, the 30 days in R4 should be changed to 60 days. Even though the language allows the PC or TP to extend the time, there is no assurance that such an extension will be granted.
No
The prior comments to Q#2 regarding a Section 1600 data request instead of a standard apprly to MOD-033-1 also. But with resepct to the specific approach taken in MOD-033-1, we have these comments: R1 requires each PC to validate performance for “its planning area.” Throughout NERC, ERCOT is the only entity that is a PC as well as an Interconnection. The Eastern Interconnection has 54 PCs and in WECC has 29 PCs. A PC’s modeled performance versus its actual performance for “its planning area” is dependent upon data within the Interconnection. That data includes data for entities submitted to OTHER PCs. A PC’s modeled performance is also dependent on the correct modeling by other PCs. In other words, within an Interonnection with multiple PCs, the data and modeling decisions of each PC within an Interconnection impacts all PCs validation ability within that Interconnection.
a. There should be a requirement for each PC to coordinate with the other PCs within its

Interconnection in R1. b. To prevent data errors, data should be validated in MOD-032-1 by the data owner prior to submission and checked by the PC after it is submitted. There is no requirement in MOD-032-1 for the PC to confirm that the data submitted by a data owner is reasonable. R4 in MOD-032-1 should require that the PC perform data validation, and as a result of such data validation efforts, it may request data clarification under R4.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We question the need to ask this question when the consolidated standard is already posted for commenting and balloting. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard development/revision project. Posting the standard for balloting at the same time suggests that there is already a foregone conclusion on the need and the scope for this project , and that the industry's input on SAR would seem irrelevant. The IESO understands that posting a SAR and the draft standards for comment at the same time can improve standard development efficiency, and we support it to the extent that sufficient technical information has been obtained to facilitate the development of a draft standard at the informal outreach stage. However, we are very concerned about the fact that the industry was asked to ballot the draft standard when the need and scope of the draft standard have not been commented on and supported by the industry, and the standard itself has not been drafted by a formal standard drafting team. Such an approach appears to: a. Deviates from the normal standards development process as presented in the Standards Process Manual (SPM); b. Contradicts and perhaps violates the intent of the established standard development process and ANSI principles to have new and revised standard formally developed through an open and inclusive process before being presented to the RBB for balloting. The industry is being asked to ballot a set of standards that has not been formally developed. This concept appears to be fundamentally flawed. We propose that the SDT convey our concern to the NERC senior management and the Standards Committee. We further suggest that NERC and the SC evaluate alternative approaches or make revisions to the SPM to provide the needed flexibility that can further improve the efficiency in standard development if certain elements in the existing SPM are assessed to restrict such improvements.
Yes
a. R2: This requirement has an ambiguity regarding the exchange of information, specifically: who makes a request, and who receives the results. We recommend that the following phrasing resolves this issue: R2. When a Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider within a Planning Coordinator's planning area requests the data requirements and reporting procedures, the Planning Coordinator shall provide to the requesting party the data requirements and reporting procedures within 30 days. b. R3: The sentence "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." is not needed since it is not a requirement. It is a measure of compliance, which is already adequately captured in Measure M3. c. R4: This requirement generates the following concerns: • A need to strengthen the stipulation for the PC to provide a technical reason • While 4.2 may account for the acquisition of user models, R4 overall reads as an undue emphasis on dynamic data that does not allow for the acquisition of steady-state (or other) data not previously defined under R1. This should be more generic to accommodate evolving modeling requirements. R4.2 should then be clarified to specifically account for non-standard models not supported by vendor software, placing responsibility on owners who are more easily made accountable to the PC, rather than on vendors who are not. As such we propose that R4 be worded as follows: R4. Upon delivery of written notification from its Planning Coordinator or Transmission Planner regarding a request for data, whether resulting from a technical concern with data submitted under Requirement 3 or a revision to the data requirement defined under Requirement R1, and whose notification shall include the technical basis or reason for the request, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: 4.1 Provide either the requested data or an explanation with a technical basis for not providing the requested data; 4.2

If requested by the notifying Planning Coordinator or Transmission Planner, provide additional data describing the characteristics of the model that would enable accurate representation otherwise not provided by standard software, including: block diagrams, values and names for all model parameters, and a list of all state variables; and 4.3 Provide the response with 30 calendar days, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.
Yes
a. R1: Suggest to replace "must" with "shall" to be consistent with other standards. b. VSL for R1: The second condition under Low VSL needs to be qualified that the situation only applies when the time between the previous dynamic local event and the events occurred that required a simulation within 12 months exceeded 24 calendar months. c. VSLs for R2: all "planning coordinator" should be capitalized. d. R2: This requirement generates the following concerns: • The Realability Coordinator or Transmission Planner may not be aware of equipment operational settings, facility impactful activities, etc., which may affect validation. Furthermore this data, as "real time" settings, may not have been made available under MOD 32 – R3,R4. As such responsibility must be expanded to equipment owners to provide "actual system behaviour data". Without expanded accountability, RC and TP may not be able to acquire this data on the PCs behalf. As such we propose that R2 be worded as follows: R2. Each Reliability Coordinator, Transmission Operator, Generator Owner, Load Serving Entity and Transmission Owner shall provide actual system behaviour data (or a written response that it does not have the requested data) to any Planning Coordinator that the Planning Coordinator requests to perform validation under Requirement 1 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. e. R2: This requirement generates the additional concern that entities are only required to provide data upon request, in particular operational settings. It may take some time for the PC to identify the cause of discrepancies during validation, and may ask for the wrong information (modeling vs. setting), for example receiving a governor model may not include the detail that it has been turned off. Consequently it is recommend that either MOD-032 or MOD-033 contains containing some language that requires each RC, TO, GO, LSE and TO (described above) to "self report" to the PC any changes in operational settings or other impactful actions within a certain period of such change.
Individual
Michelle R. D'Antuono
Ingleside Ccogeneration LP (Occidental Chemical Corporation)
No
Yes
Ingleside Cogeneration appreciates the rapid development team's effort to ensure that MOD-032-1's data specifications are consistent with existing regional requirements. The industry has generally settled on a modeling structure that includes steady-state, dynamics, and short-circuit data – and the specific elements are appropriate to the needs of the planning function. Although they will not affect our positive vote, we would like to raise two logistical concerns that the drafting team should consider. First Planning Coordinators should identify those items in their data specifications that correspond to Attachment 1. We anticipate that Compliance Enforcement Authorities will ask downstream data suppliers such as ourselves to prove that every line-item was satisfied. PCs may use different language to describe a modeling parameter for a variety of very good reasons – and the Attachment 1 elements may be hidden in a much larger reporting template. They should make the connection up front, so that we are not left in the position to do so. (It seems logical that PCs would need to do so anyways to demonstrate their compliance with MOD-032-1 R1.) Secondly, Planning Coordinators should provide the latest data they have on hand when the data template is issued. This would eliminate any uncertainty about the accuracy of data in the PC's database versus that which was supplied (i.e.; due to a data entry error or some other cause). In addition, it offers the opportunity to request a reason for any parameter that has changed in the interim – which may be useful reliability information as well.

Yes
Ingleside Cogeneration agrees with the approach the rapid development team has taken to validate wide-area planning models. The Planning Coordinator relies most heavily on the performance data provided by Reliability Coordinators and Transmission Operators to improve model accuracy – and traditionally has worked closely with those entities in this regard. In addition, we believe that the PC and/or TP has other enforceable recourse to bring in other downstream entities if needed. In particular, the Generation Validation standards that are pending FERC's approval already call for the verification of complex governor and excitation systems in response to frequency and voltage transients. This should be sufficient to assure that the PC's wide-area models have the best generator-related information available – and further GO requirements are not needed.
Individual
Roger
Dufresne
No
Yes
We do not have found requirement equivalent to this in MOD-032-1: 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
Brett Holland
Kansas City Power & Light
Agree
Florida Municipal Power Agency
Individual
David Jendras
Ameren
No
No
With respect to the applicability of this standard, we have concerns regarding the replacement of the Regional Entities with the PC in the standard. In addition to taking time for the PC's to ascend the learning curve associated with collecting, testing, and forwarding the data to the ERO or its designee (responsible for assembling the final interconnection models) if they have not been involved with this process to date, the opportunities for seams issues to occur would be significant and ongoing, with the rearrangement of roles to replace 8 regions with ~50+ PC entities. R2: We believe that without a uniform data standard the quality of the data may decrease. Using the Region as a collection point has merit in ensuring that the data requirements are consistent. Therefore, it would be preferable to retain the Regional Entities in the process as at present. R3: A major concern involves consistent and comparable data submitted. We believe that removing the Regional Entities as the collectors will necessitate development of a procedural manual that all must follow to assure workability of the model assembly process. R5: We request that Language is included in the standard to reflect that the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection

models, and should provide the procedural manual for assembly of model data to insure consistency and usability of the models. This would help address concerns raised regarding consistency of data mentioned in our comment to R2. We request that the range of time values shown under the VSL's for draft standard MOD-032-1 R3 should match those shown for the existing MOD-010-1 R2 or MOD-012-1 R2.
Yes
We request the SDT to provide additional clarification regarding what would constitute a 'dynamic local event' as cited in R1.2?
Group
SERC Planning Standards Subcommittee
Jim Kelley
No
No
MOD-032-1: R1 We have concerns regarding replacement of the RRO with the PC in the standard. In addition, with the learning curve time associated with testing and forwarding to those finalizing models the opportunities with seams issues seem significant and possibly on-going with the increase of PCs involved. Therefore, it would preferable to maintain the Region in the process as at present. R2. It appears that without a uniform data standard the scope of the data may not be uniformed. Using the Region as a collection point has merit in ensuring that the data requirements are consistent. R3. The concern centers on consistent and comparable data submitted. Removing the Regions as the collectors may necessitate development of a guideline manual that all accept to ensure that data is consistent. R5. The SDT is requested to include clarification language that the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection models, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection models, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection models and each will provide a procedural manual for their area to ensure data submittal is consistent.
Yes
The SDT is requested to review the other MOD standards to ensure that GOs are covered and required to submit data when requested. The comments expressed herein represent a consensus of the views of the above named members of the SERC PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Denise Yaffe
Southern California Edison
No
No
SCE appreciates the standards drafting team's effort to integrate six existing data modeling standards into two concise. MOD-032-1 and MOD-033-1 are good starting points in this effort, but additional clarifications and refinement are necessary before they can be supported. For example, MOD-032-1, R4.1 includes a provision under which Planning Coordinators and Transmission Planners might be required to use erroneous data so long as the party providing the data was able to provide some type of technical explanation supporting its use. The Planning Coordinator and Transmission Planner should have the ability to reject data when they find deficiencies with the data provided to them.
Yes

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 is the right step for a NERC standard. Thank you.
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; and PPL Generation, LLC, on behalf of its NERC registered affiliates. 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. Comments: Is it the intent for these standards to address: Operating as well as Planning Models? Models used for EOP-005 Blackout recovery analysis requirements? What is the relationship between MOD-032 & 33 and the TOP-2 and VAR-2 requirements to report short term MW and MVAR limitations and FAC-008 ratings? Should they be consolidated in these requirements similar to pulling transformer data reporting requirements from VAR-002?
No
GO requirements in MOD-010, 11, 12 and 13 are presently well-defined and reasonable in scope. MOD-032 proposes to leave the type of model, level of detail, size cutoffs (if any), case types and scenarios to be established at some future time by the Planning Coordinator. This creates uncertainty because it requires approval of a standard without all of the relevant provisions being known. The request for station service auxiliary load (for new plants) information in Attachment 1 of MOD-032 may not provide sufficient reliability benefit to cover the cost. For example, an extremely complex algorithm would be needed in some cases to relate this parameter to load level and other operating conditions (summer vs winter, limestone preparation on vs off etc.), and it is doubtful that developing detailed inputs in this respect would have a meaningful impact on system stability analyses. The proposed approach could also lead to unjustifiable regional variances. A mandate by the TP to supplement TGOV1 fossil models with an LCBF1 outer-loop representation may generally be reasonable, for example, but what is there to prevent a demand that the units be migrated and validated to the much-more-difficult TGOV5 model? All obligations should be clearly set forth in the proposed reliability standard when it is posted for voting. For example, the standard could require that the TP/PC reach agreement with the GO regarding required models. The 30-day deadline specified in R4 is far too short for independent GOs who, lack in-house modeling specialists and, would need to contract for the services needed to develop responses. The time limit should be at least 90 days. Mandating in Att.1 that GOs provide short-circuit data at the generator, GSU and transmission line should be accompanied by a requirement that the TO collaborate with the GO in transposing generator nameplate information to high-side values. We also recommend that the SDT consider the comments prepared by the Florida Municipal Power Agency (FMPA) with regard to principles of technical and economic justification.
Group
seattle city light
paul haase
Agree
Sacramento Municipal Utility District (SMUD)
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Florida Municipal Power Agency (FMPA)

(1) The proposed model validation process should be restricted to the validation of models concerned with the operating horizon, and not the planning horizon. Validating a planning horizon model with past operating data is not an efficient use of time and will deliver only de minimis benefits, if any at all. (2) Requirement R2 in proposed MOD-033-1 is redundant with current requirements under Standard IRO-010-1a and pending Requirements in TOP-003-2 for requesting operating data. Therefore, if an entity forgets to submit operating data for validation, that entity could be found liable under three separate Standards. All requests for operating data should be confined to one Standard. (3) The language “too large” in Requirement R1.3 is vague and the Application Guidelines do not assist with defining what “too large” entails. Please clarify this language in the Standard itself. (4) Is the Application Guidelines section of the Standard primary law or is it mere suggestive guidance. For example, the Requirement R1 section of the Application Guidelines states that when “performing the comparison required in part 1.1., the PC should consider, among other criteria: (1) System Load; (2) Transmission topology and parameters; (3) Voltage at major buses; and (4) Flows on major transmission elements.” (emphasis added). If a PC were not to consider any of the above criteria, would it be found in violation of R1.1? It appears not as the term “should” as opposed to “shall” was utilized. In addition, if any criteria, quantitative or qualitative, are later drafted into the Standard, why can’t the Standard Drafting Team include them in the Requirements as opposed to the Application Guidelines section?
Individual
Kayleigh Wilkerson
Lincoln Electric System
MRO NSRF
No
Although supportive of the overall objectives in developing MOD-032-1, LES is concerned by the lack of a detailed plan on how the eastern interconnection cases would be developed going forward. Additionally, there is no proposed plan on how to build the regional power flow and dynamic cases or whether these regional cases would even be built any longer once MOD-032-1 is an enforceable standard. Although Requirement R5 requires each Planning Coordinator (PC) to submit data to the ERO or its designee to support creation of the interconnection models, the PCs have no obligation to collect data on the same schedule and no obligation to build the same set of models. Per the Rationale for R5, MOD-032-1 assumes that “entities are successfully coordinating their efforts” thereby negating the need to establish a process for building the larger interconnection-specific model. However, the drafting team fails to account for the existing regional processes that currently ensure successful coordination which would potentially be eliminated pending the standard’s approval.
Individual
Diane Barney
New York State Departement of Public Service
It is premature to be voting at all for the standard at this point in the process. Two major pieces of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft standard.

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Individual
dmason
HHWP
No
Yes
Each Planning Coordinator must submit the data provided to it under Requirement R3 to the ERO or its designee to support creation of the interconnection model(s) that includes the Planning Coordinator’s planning area as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]. The reliability related need for this data to be provided to the ERO is not clear. This data and the creation of Interconnection wide model should not be an ERO function. It is more properly a Planning Coordinator function
Yes
Individual
Steven Mavis
Southern California Edison
Yes
SCE appreciates the standards drafting team's effort to integrate six existing data modeling standards into two concise. MOD-032-1 and MOD-033-1 are good starting points in this effort, but additional clarifications and refinement are necessary before they can be supported. For example, MOD-032-1, R4.1 includes a provision under which Planning Coordinators and Transmission Planners might be required to use erroneous data so long as the party providing the data was able to provide some type of technical explanation supporting its use. The Planning Coordinator and Transmission Planner should have the ability to reject data when they find deficiencies with the data provided to them. Please see SCE's completed comment form for additional comments.
Yes
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Individual
Jay Teixeira
Electric Reliability Council of Texas, Inc.
IRC SRC
No
Yes
In R1.1 Attachment 1, the following “At a minimum” data reporting requirements should be added: For Steady-State: Add to item 2 Aggregate Demand at each bus: Add item 2d, Load Characteristics – specify percent large motor, small motor, resistive, discharge lighting, other of load at bus. Add to item 3 Generating Units: Collector system data showing positive, negative, and zero sequence data for equipment below the transmission level step up transformer. For wind farms and similar widespread equipment, this would be the collector system showing complete feeder circuits to pad-mount transformers on each turbine. For wind turbines – add specification of turbine type such as type 1, 2, 3, or 4. Add to item 4 AC Transmission Line and 6 Transformer: 4b and 6h. ratings – add other specified ratings such as 15 minute and conductor/transformer emergency ratings. For Short-Circuit: For item 1 Positive Sequence – add for both saturated and unsaturated For item 2 Negative Sequence – add for both saturated and unsaturated For item 3 Zero Sequence – add for both saturated and unsaturated Add to item 3b (Generator) and 3d (Transformer) under Zero Sequence data: Add grounding type and ground equipment such as neutral transformer with resistor value with appropriate data to convert to specified per unit quantities. Add new item after item 4 to request controlled fault current limits for sub transient, transient, and synchronous time periods for type 3 without crowbar and type 4 wind turbines. Add new item after item 4 to request Direct Axis Subtransient, Transient and Synchronous reactance both saturated and unsaturated.
Yes
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC Planning Standards Subcommittee
Group
NAGF Standards Review Team
Patrick Brown

Yes
1. Is it the intent for these standards to address Operating as well as Planning Models? Models used for EOP-005 Blackout recovery analysis requirements? 2. What is the relationship between model standards and the TOP-2 and VAR-2 requirements to report short-term MW and MVAR limitations and FAC-008 ratings? Should they be consolidated in these requirements similar to pulling transformer data reporting requirements from VAR-002? 3. The GOP might also be included if short-term limits are in the scope of this standard. 4. Detailed Description add "and when changes to equipment are made during the life of the plant" to the sentence "Generator Owners must provide accurate model data of their systems during the interconnection process". This is inferred in R3 of MOD-32. This may also need to cover any pre-change notifications required outside of an interconnection request for existing units that are changing modeled equipment but not doing uprate changes. 5. It's not clear what the issue is with Proprietary Models if it is understood that the GOs must supply a model that has been validated against commissioning test data. I understand this was an issue for early winds farms but efforts have been made to develop standard wind models for different designs. Is this really a failure during the interconnection process and should be addressed in the FAC-001/2 standards related to new generation?
No
1. The SRT questions the reliability based need for R5.2. We believe that the scope of the documentation should be narrowed to only include major data modifications that could affect the model. To include all data modifications would create an unnecessary administrative burden on the PC. Another suggestion would be to add a requirement that the ERO or its designee request this type of documentation, similar to R4, as part of the model building process. 2. GO requirements in MOD-010, 11, 12 and 13 are presently well defined and reasonable in scope. MOD-032 proposes to leave the type of model, level of detail, size cutoffs (if any), case types and scenarios to be established at some future time by the Planning Coordinator. This constitutes asking us to issue a blank check regarding compliance burden, which is unbusiness-like. 3. Indications of excessive scope creep are already evident in Attachment 1 of MOD-032, e.g. station service auxiliary load (for new plants). An extremely complex algorithm would be needed in some cases to relate this parameter to load level and other operating conditions (summer vs. winter, limestone preparation on vs. off etc), and it is doubtful that developing detailed inputs in this respect would have a meaningful impact on system stability analyses. 4. The proposed approach could also lead to unjustifiable regional variances. A mandate by the TP to supplement TGOV1 fossil models with an LCBF1 outer-loop representation may generally be reasonable, for example, but what is there to prevent a demand that the units be migrated and validated to the much-more-difficult TGOV5 model? All obligations should be forthrightly put on the table at the time a standard is posted for voting. 5. The 30-day deadline specified in R4 is far too short for independent GOs who, lacking in-house modeling specialists, would need to contract for the services needed to develop responses. The time limit should be at least 90 days. 6. We also recommend that the SDT consider the comments prepared by the Florida Municipal Power Agency (FMPA), especially as regards adhering to principles of technical and economic justification. 7. On R1: Uniformity of the data request form is desirable. R1 data requirements should be sensitive to the life cycle of the generator (age, data availability for pre-1970 units, units in various stages of project development, planning, and start up), or to unconventional data requests that would require reverse/extensive engineering techniques to fulfill. 8. R2 is purely administrative and should be eliminated. The PC should simply deliver the data requirements and reporting procedures to the BAs, GOs, and TOs. etc. once they have developed or revised them. 9. Attachment 1 should provide additional details of precisely what "minimum" data is required - for example, on the generator, which time constants and which reactances are required. 10. For the VSL on R3, perfect data submission is in violation (0% missing/unformatted/late is less than 25%) - please correct. Consider some minimum level of data shortage/formatting/tardiness being acceptable rather than instituting a "zero tolerance" position - say 5% up to 25% is the Lower VSL. A zero tolerance for a VSL seems inconsistent with the NERC Reliability Assurance Initiative and risk based compliance and enforcement approach. 11. For R4.2 - an explanation with a technical basis for maintaining the current data should be allowed here too (like R4.1). 12. Attachment 1, steady state, item 3c - station service auxiliary load data should be restricted to normal plant configuration for the GO 13. Attachment 1, steady state, item 3d - please define what is meant by "regulated bus". 14. Attachment 1, steady state, item

3e - is this the voltage schedule? 15. Attachment 1, steady state, item 3f - what value is the % ownership to the model? 16. Attachment 1, steady state, item 3h - please clarify what this means for generating units. 17. Attachment 1, steady state, item 6g - please explain what this rating is. 18. Attachment 1, steady state, item 9 - we believe that there should be a requirement for the PC to provide technically based reasons for expanding the data request beyond what is listed in Attachment #1. (Requirement 1, Attachment 1 - steady state, item 9). 19. We recommend R5 be removed from the draft standard altogether and that the PC deliver the data in response to a NERC Rules of Procedure Section 1600 data request. This requirement is purely administrative.
Individual
Patrick Farrell
Southern California Edison Company
No
No
SCE would like to thank those who have worked diligently during the MOD B informal standards drafting process. We strongly support the need for consolidating and updating the existing MOD standards with respect to data requirements and the specification of functional entity responsibilities. However, we are submitting a negative vote in hopes that the SDT will consider revisiting the intent of R4. While we recognize that the entity responsible for the data is ultimately the expert on their particular piece of equipment or facility, we believe the MOD standards intend to ensure the accurate and reasonable assessment of the interconnected electrical grid in order to ensure that long-term reliability is maintained and adequately planned. We recommend that the SDT revise R4 to include an additional sub-requirement to R4.1 which specifies that if the usability or data differences cannot be resolved between the identifying entity and the data owner, the PC or ERO may act as an arbitrator to propose a final modeling decision. Our intent is to ensure that a data owner may continue to stay in compliance by actively providing technically-adequate data AND that the usability of the larger, interconnected model will continue to serve within the original intent of the MOD standards. Our experience has shown that a technical justification may exist for equipment to be modeled in a certain manner, but that added detail or limitations of modeling software can detract from the overall simulation and study quality. Various system conditions and physical equipment design limitations will sometimes prevent a perfect mathematical model from being developed. SCE supports the elevated, system-wide perspective that the TP or PC would have as an appropriate measure of usability for study purposes and support any revision to R4 that reflects this wider-perspective expertise. We thank the SDT for the opportunity to comment and hope that a reasonable revision to MOD-032-1 can be developed which will support the spirit and intent of this comment.
Yes
SCE would like to thank the drafting team and NERC for providing the opportunity to comment on the new proposed modeling validation standard. We feel 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 is the right step for a NERC standard.
Group
Puget Sound Energy
Eleanor Ewry
No
Yes
The approach of MOD-032-1 currently aligns with existing data collection practices.

R1.6 - It should be allowable for the Planning Coordinator to provide a schedule to the GO, LSE, RP, TO and TSP outside of the 13 month requirement. Within WECC, the Generator Testing Policy requires the GO to validate dynamic models every 5 years or when major equipment changes take place. The PC should be able to point to the RRO testing policy and timeline with language such as "...at least once every 13 calendar months or according to a schedule provided by the RRO." This would lessen the burden on the GO to provie annual updates for data that will not change that frequently and also allows for future flexibility with the proposed MOD-024 through MOD-027. R4 - Who will be the final authority if the PC or TP and the entity submitting data can not agree on a valid model? There should be a clause that the data shall be usable within the platform specified by the PC or TP.
No
There seems to be little technical basis for the requirements in MOD-033-1, specifically with regards to defining the types of events against which models need to be validated and how frequently this should happen.
R1.1 - The system power flow model for a Planning Coordinator Area may not change significantly enough to warrant validating the model every 24 months. Is there a technical basis for choosing 24 months as the time period for which the system power flow model must be validated? Also, it should not be up to each individual Planning Coordinator to determine the how large the discrepancy between the system model and actual system performance can be. This should be determined by the RRO or NERC based on sound technical reasoning. R1.2 - What would constitute a dynamic local event? This implies that it would not be required for the Planning Coordinator to validate dynamic models following a system-wide event. Will this be the responsibility of the RRO? What distinguishes a dynamic local event from a system-wide event (number of Planning Coordinator Areas impacted, amount of generation/load impacted)? These should become NERC defined terms.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
R4 requires a generator response to technical concerns within 30 days unless a longer time is agreed to by the requesting entity. IPPs, especially the smaller units, do not have full-time technical resources on staff to address this request. The process of identifying engineering contractors with the available resources, bidding the job, receiving manufacturer technical support for the questions, and developing and submitting a response is likely to take well beyond 30 days. Suggest changing the language to 90 days, or to "or such time as proposed by the entity, if there is a submitted technical reason why a longer time period is required to address the concern". Under "at a minimum" requirements, there is no valid reason to require percentage of ownership. R1 should be changed to require a technical justification for expanding the "at a minimum" requirements, to prevent requests for data which add little to the model, but impose costs on the entities who receive the request.
Yes
Individual
Silvia Parada Mitchell
NextEra and FPL
Yes
NextEra believes that any consolidation of the MOD Standards needs to also consider that the working groups associated with the subject matters are, in most cases, different staff members e.g. Planning (steady state), Protection & Control (short circuit), Stability experts (dynamic cases). Therefore, the merging these standards must include organizational framework that separates specific subjects in the new Standard(s), otherwise the Standards will create unintended inefficiencies. NextEra Energy is

encouraged by the direction of MOD-032-1, but believes that it needs considerable refinement, including technical corrections, prior to becoming a mandatory Reliability Standard. These comments are provided to assist the Standards Drafting Team refine MOD-032-1 so that it may be both technically correct and clear.
1. Revise R1.1 to read as follows: “1.1. Specification of the required data listed in Attachment 1;” It is not good drafting practice and there is insufficient technical rationale for the inclusion of “at a minimum.” If the Standards Drafting Team desires a Planning Coordinator to in its own discretion consider other data, it better serves stakeholders to draft a technical guidance paper to suggest the consideration of other data than to do so via a mandatory requirement. Further, such a drafting practice is inconsistent with several of the Ten Benchmarks of an Excellent Reliability Standard (e.g., measurability no. 4, clear language no. 8). Thus, NextEra recommends that “at a minimum” be deleted. 2. Delete R2. The rationale for this requirement is that a change in ownership may necessitate the need for the Planning Coordinator to provide its data to a “Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider.” This rationale is supposition and insufficient to include as a mandatory requirement. Further, it implicates a commercial matter; a change in ownership includes contractual obligations, which is a better place for the consideration of the need to exchange data than a mandatory requirement. Further, inclusion of R2 implicates P81 criteria. P81 Criterion A states “The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.” R2 satisfies Criteria A in that it is a requirement that is related to a generalized concern related to data exchange, and not specific performance or operational issue. Further, this requirement also implicates Criteria B 1 (administrative), 2 (data collection/data retention), 3 (documentation), 4 (reporting) and 6 (commercial) of P81. There is no rationale provided why there needs to be a legal requirement to provide data in the manner set forth in R2. Moreover, data exchanges such as the one prescribed in R2 can be accomplished via the regional planning committees or a simple phone call, which is another reason not to mandate such via a Reliability Standard. For all the forgoing reasons, R2 should be deleted. If the SDT believe this is an issue that should be addressed in some manner, NextEra recommends it issue a good business practice document. 3. Delete R5. Requirement 5 is a data submittal requirement that satisfies the P81 Criteria A and B 1 (administrative), 2 (data collection), 3 (documentation) and 4 (reporting). In the P81 filing before FERC similar data requirements were deleted from other Standards, therefore, it is counterproductive and contradictory to the P81 efforts to include R5 in the Standard. If the SDT believes this data is important for the ERO to obtain, it should be accomplished via a Section 1600 data request, as the Misoperations SDT determined for Misoperations data to be provided to the ERO. 4. Attachment 1 should not include all the data listed and the language should be clearer. a. For the same reasons set forth in response to R1.1, the “at a minimum” language is inappropriate for Attachment 1. b. Steady state (SS) 2c. load type load type data is not required for planning studies and thus should be deleted as technically incorrect. Also, 2c specifies “etc.” which should be deleted as “etc” is not appropriate drafting practice for mandatory Reliability Standard. such a drafting practice is inconsistent with several of the Ten Benchmarks of an Excellent Reliability Standard (e.g., measurability no. 4, clear language no. 8). Thus, NextEra recommends that “etc” be deleted. c. SS 3c. plant aux load is netted with generation, thus the Transmission Planner will know the net generation; therefore, it is not necessarily to include the “aux load” and it should be deleted. d. SS 3h share of reactive contribution for voltage regulation. This refers to PSS/E RMPCT data value that is optional. RMPCT may be useful for some, but may also cause problems when plant dispatch changes and RMPCT no longer add to 100. e. SS 3j. prime mover type is not needed for planning studies; therefore, inclusion of prime mover type is technically incorrect and should be deleted.
No
NextEra Energy is concerned with the direction of MOD-033-1. While NextEra acknowledges that FERC directives are associated with MOD-033-1, it strongly recommends that the Standard Drafting Team and NERC Staff reconsider its approach to addressing the FERC directives. The primary concern is related to the how the term validation is defined and the clarity on the amount of flexibility or discretion provided to entities to develop a process to validate. The challenge associated with these issues seems to be to be acknowledged in the rationale for R1 that states in part “Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language.” The following are general comments that provide a basis for NextEra’s overarching

concern that the direction of MOD-033-1 needs to reconsidered. • The proposed MOD-033 requirements for validation of dynamic models grossly underestimate the amount of work required for these analyses. Attempting to recreate an event with dynamic simulation studies is an extremely complex undertaking that may require input from transmission operators and reliability coordinators throughout the interconnection and can take more than a year to perform. The scope, complexity and need for the analysis is dictated by the event. While power systems experience outages on a daily basis, very few of these events cause enough of a perturbation to reveal significant dynamic response; consequently mandating a validation effort every two years will force a large level of engineering effort with questionable benefits. • Differences between recorded system response and dynamic models response are difficult to associate with a specific model due to the manner in which generators affect each other throughout the interconnection. For example is a voltage dip at station C due to the behavior of nearby generator A or nearby generator B or is it due to load behavior. Cause and effect are only clearly delineated in generator open circuit tests when the generator is disconnected from the power system. • The validation requirement applies to Planning Models but Planning Models cannot be used to validate actual system events because Planning Models correspond to a best guess of a future point in time and assume normal facility availability e.g. does not account for temporary system clearances. • Planning Models would first need to be converted to represent conditions at the time of the event. System response tends to be strongly influenced by initial conditions. Converting a Planning Model to the initial condition for an event is extremely laborious. Cooperation of all utilities is required to collect and provide system condition data at the time of the event. Once this large volume of data is assembled, it can take a team of engineers two to three months to convert the Planning Model. • The idea that Planning Models can be adjusted to exactly match recorded system response is false. If one is successful in identifying aspects of the Planning Model that lead to divergence from observed BES response, it may be possible to improve the match. An exact match is beyond the realm of possibility. Compliance metrics for validation are therefore not suitable. • Benchmarking a system event and adjusting models to improve accuracy is an extremely labor intensive engineering process that requires the highest level of engineering expertise. Requiring this exercise every 2 years will be extremely burdensome to the industry if not impossible • Most system events do not cause system perturbations large enough to reveal significant characteristics of dynamic response. Biennial analysis of mild disturbances will consume large amounts of engineering manpower analyzing events that reveal little of the BES actual character. • The scope and type of dynamic analysis varies greatly and depends on the nature of the event. Analysis of large scale events that do reveal significant dynamic response already occurs in accordance with ERO efforts or directives. These efforts should be encouraged but are not suitable for compliance enforcement. • Improvements in dynamic model accuracy would be expected with the generator verification tests called for in the proposed MOD-026 Standard. • Reliability Coordinator should be responsible for the R1.1 that deals with comparing steady state models to recorded system behavior. Operating Horizon steady state models would be used for this as the model topology, loads and dispatch should be much closer to the system conditions at the time of an event. Choosing the Planning Coordinator as responsible means the starting point would be Planning Horizon models that require more extensive analysis and modifications to match them to event conditions. Based on these concerns, recommend re-writing R1 And its sub-requirements as follows: R1. Each Reliability Coordinator must implement a documented process that validates, to the extent reasonably possible, through a bandwidth or tolerance level approach the data used for steady state (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses or simulations of actual system response that includes the following items: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. A simulated validation through a bandwidth or tolerance level approach of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other real-time data sources to check for system significant discrepancies that the Reliability Coordinator at least once every 24 calendar months.
Recommend re-writing R1 And its sub-requirements to be limited to the following and read as follows: R1. Each Reliability Coordinator must implement a documented process that validates, to the extent reasonably possible, through a bandwidth or tolerance level approach the data used for steady state (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses or simulations of actual system response that includes the following items: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. A simulated validation through a bandwidth or tolerance level approach of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other real-time data

sources to check for system significant discrepancies that the Reliability Coordinator at least once every 24 calendar months.
Individual
Anthony Jablonski
ReliabiltiyFirst
ReliabilityFirst votes in the affirmative because the draft standard establishes consistent modeling data requirements and reporting procedures to support analysis of the reliability of the interconnected transmission system. ReliabilityFirst offers the following comments for consideration: 1. Requirement R5 - Requirement R5 states that the PC shall submit data to the ERO's designee for interconnection models. In the Eastern Interconnection (IE), the ERAG MMWG builds the interconnection cases utilizing Regional Entity (RE) staff. Some of the Regional Entity's may pull out of this process once these standards are approved as there is no requirement for them to support it. The Planning Coordinators are under no obligation to supply funds or build interconnection models, only to submit the data. Currently the six RE's in the EI share the cost of building the models. ReliabilityFirst recommends that NERC should name their designee in the EI, well in advance of the approval of these standards to ensure a smooth transition. 2. General Comment – ReliabilityFirst recommends the drafting team develop a mapping of Registered Entities to their respective Planning Coordinators. A number of entities may not necessarily know who their associated Planning Coordinator is.
Group
ISO/RTO Standards Review Committee
Greg Campoli
No
The format of MOD-032 may be an issue given that: R1 requires "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area…" The highlighted phrase is not a defined/measureable mandate. Moreover the phrase is not required (the phrase is more of a good/best practice) and has the potential to invite subjective concepts if one or more of the TPs are not satisfied with the "level" of inclusion it gets. The SRC would suggest deleting the phrase "in conjunction with each of its Transmission Planners" The SRC suggests M2 be rewritten to make clear who "it" is in the phrase "… a statement by the PC that IT has not received a request for ITS data requirements…." M2 clearly refers to the PC but the phrase in question implies that the receiving entities are involved they are asking for data. It would be better if the phrase in question were rewritten to "… a statement by the PC that the PC already had all of the data required to meet R1." R3: The last sentence states "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." This statement is not needed since it is not a requirement. It is a measure of compliance, which is already adequately captured in Measure M3. R4: The phrase "including the technical basis or reason for the technical concerns," implies that the PC is required to provide this in the written notification but there is no such a requirement stipulated anywhere. If this is not a requirement, then it does not add any value to Requirement R4 as this requirement itself stipulates the tasks required of the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider upon receiving a notification from the PC. R5 requires "Specification of the case types or scenarios to be modeled…" This requirement is formatted as a "fill-in-the-blanks" requirement, a format that FERC asked the Industry to avoid. The requirement asks the PC to fill in which cases are run. This would not result in a common North American assessment of conditions. The SRC would suggest that the basic set of cases be defined and thereby leaving the PS's to run any additional cases it deems as

appropriate. R5 requires data submission to the ERO "... to support creation of the interconnection model(s)". The requirement to supply data to the ERO is already required by the Rules of Procedure and need not be repeated here as a reliability requirement. Given the fact that the Requirement is not specific about which data/which study(ies) are envisioned it makes more sense to rely on the Rules of Procedure. The SAR alludes to interoperability issues among vendor-supplied programs. The SRC raises the concern that the ERO "program" may require data/formatting that is inconsistent with the entities data base. Here again the idea of placing a mandate on an asset which may change instantaneously (today its uses program A and tomorrow they use program B). One is deterministic and the other is probabilistic. Such transitions could prove costly to address. The SRC would ask if this requirement addresses a major area of concern or if it addresses a small subset of outliers? If it is a small subset, then the SRC would ask the SDT to consider a Dispute Resolution alternative. If an entity does not provide requested data, then the PC and Entity must go to a DR session to get the matter resolved.
The SRC believes it would be helpful to clarify the meaning of the word "validation". Is a PC compliant if it has a program "designed to represent conditions" or must the PC have a program that duplicates or can be made to duplicate actual conditions. The former approach does not punish the PC if the program fails to meet an Auditor's view of accurate results. The latter approach may result in PCs being required to simulate a state that cannot be duplicated.
Group
SPP Standards Review Group
Robert Rhodes
No
The SAR and overall scope of the project are satisfactory.
Yes
We suggest that the drafting team consider the following rewrite of the SEVERE VSL for R2: The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them in greater than 75 calendar days. Or, the Planning Coordinator did not provide its data requirements at all.
Yes
We have a concern regarding specifically which models are to be validated against the Real-time data. This should be specifically spelled out in the standard. Transmission Operator is missing in the 6th line of M2. M2 should read '...or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation...'.
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) SAR, Brief Description - replace " BPS " with " Bulk Power System (BPS) " as this is the first instance of this term in the document. (2) Manitoba Hydro believes that there is no discerning the owner of operational models vs. planning horizon models. The PC should not be responsible for the operational models (current year models). (3) Manitoba Hydro believes that even though the PC can create Planning Horizon models for it's region, they cannot build a 'standalone' model to perform studies without the coordinated efforts of external entities within the planning horizon (ie. interconnection models). (4) The ERO or designate standards/process is unidentified for the interconnection model (ie. bus numbering sequence, area ownership, transactions etc.).
Yes
No comment.

No
(1) General Comment - replace “ Board of Trustees ” with “ Board of Trustees’ ” throughout the applicable documents/standards for consistency with other standards.
(1) Guideline and Technical Basis - add the bracketed acronym (PC) following the first instance of the words “Planning Coordinator”. Moreover, subsequent instances of these words should be replaced with their acronym “PC”. (2) General Comment - replace “ Board of Trustees ” with “ Board of Trustees’ ” throughout the applicable documents/standards for consistency with other standards. (3) Manitoba Hydro believes that there is no discerning the owner of operational models vs. planning horizon models. The PC should not be responsible for the operational models (current year models). (4) Planning Horizon models are built within certain parameters (summer peak, generation conditions, future generation and transmission projects) and utilize ‘Best Guess’ parameters for future facilities and therefore cannot be used as ‘validated models’. Operational models are more suited for tasks of model validation as they more closely represent near term system topology. Also, there are no guidelines to suggest an ‘industry standard’ on manipulating data (load, generation, area transactions and losses) for analysis of a system event.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
For the SAR, p8, sect e., citing wind and PV resource equipment that is already interconnected, AECI questions whether this project's goal of mandating data-sharing can actually serve to override legal non-disclosure agreements that have already been executed between utilities and manufacturers.
Yes
(1) AECI definitely appreciates the phased-approach to implementation of MOD-032-1. (2) We do wish the SDT had provided separate ballots for MOD-032 and MOD-033, so we could have been affirmed this draft while withholding affirmation of MOD-033. (3) Because we are SERC members within the Eastern Interconnection, our understanding of MOD-032-1 R5 impact, is hazy at best.
No
FOR: MOD-033-1 R1.2 REPLACE: "through simulation of the next dynamic local event" WITH: "through simulation of their latest dynamic local event older than 24 months" OR WITH: "through simulation of their next oldest dynamic local event that is older than 24 months" RATIONALE: the current wording requires that Planning Coordinators accurately predict their next dynamic local event, which is near impossible
Due to the complex nature of producing meaningful data validation tools, AECI appreciates this SDT's Implementation plan for MOD-033-1, having allowed for at least 3 years following approval before becoming effective. FOR: Project_2010-03_Implementation_Plan REPLACE: "within 24 calendar months after the Effective Date of MOD-033-1" WITH: "within 36 calendar months after the Effective Date of MOD-033-1" RATIONALE: Alignment of contradictory statements, where "New or Revised Standards", MOD-033-1, cites "on the first day of the twelfth calendar quarter after applicable regulatory approval".
Individual
Jack Stamper
Clark Public Utilities
No
Yes
I believe MOD-032-01 Attachnment 1 (column “Short-Circuit”) is vague on what elements it is actually referring to and offer the following suggested change in order to make it more clear: 1. Each applicable element listed in the “Steady State” column for TOs and/or GOs. Those elements are

Buses, Generating Units, AC Transmission Lines, DC Transmission lines, Transformers, Shunt Capacitors, Reactors, and Static VAR Systems. a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data d. Mutual Line Impedance Data (TO only) I believe this not only makes it more clear but also places the information request in this column into a similar format as the other two columns in Attachment 1.
Yes
MOD-033-1 Requirement 1 referes to the single modeling data standard as MOD-TBD-01. Shouldn't this refer to MOD-032-1? Since MOD-032-1 is now subject to the baloting process it seems reasonable to include a direct reference to this proposed standard. Whether MOD-032-1 passes or fails, MOD-033-1, Requirement 1 will need to be modified to refer to the correct single modeling data standard.
Group
PacifiCorp
Kelly Cumiskey
Yes
PacifiCorp maintains that this process seems out of synch. Approving a standard without approving the SAR first seems to indicate that the informal process is rushing the standards development without due diligence.
No
PacifiCorp supports the following comments: Requirements 1 from both MOD-014 and MOD-015 have not been mapped to the new proposed standard. Developing power flow and dynamic models are needed to perform the needed studies for FAC, PRC, and TPL standards. This would create a gap in the MOD standards. Which entity is developing models? There needs to be a standard directing an entity to develop models or a change in the NERC Rules and Procedures. Specific comments/questions below: Has ERAG acknowledged that they will be getting 51 raw data sets from the PCs (i.e. unsolved, incomplete data)? ERAG is not in the functional model and not subject to compliance. Can the PC's be responsible for modeling issues? The PC is really just a middle-man for the data, So it is not clear to PacifiCorp what value they bring by being included in the process? If one or more regions gets out of building models, is ERAG still the one to aggregate them? If ERAG is the region and they build the power flows is there a conflict of interest? Not everyone uses the PTI product "model on demand," as the tool the TO could use on behalf of the PC.
-PacifiCorp supports the request for clarification of item 4 of the Steady-State portion of Attachment 1 in MOD-032-1. Item 4 states, "AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO]." Why does the drafting team see the need to explicitly model series capacitors and reactors? This equipment is usually not breakered and, thus, from a contingency standpoint, is part of the line that it's connected to. Explicitly modeling series reactors and capacitors would provide misleading results when performing N-1 contingency analysis. Additionally, PacifiCorp supports the following comments provided by Florida Municipal Power Agency: -The SAR goes to great length to describe a purported problem with gaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement. -In an apparent attempt to avoid the need for a technical justification, the SAR states: "(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection." The Planning Horizon is strewn with similar unknowns that we cannot know (load models, generator dispatch, transmission construction), and this statement alone is not technical justification. However, accurate models may be needed for the Operating Horizon. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. -The terms of the Confidentiality Agreement (CA) are important to consider. These models are to be shared with all the planners within

an Interconnection. The SAR on page 5 states: "(p)roprietary models with details hidden from the user ('black box' models) or those models that cannot be shared across the Interconnection are not acceptable." How will the terms of such a CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR's claim that: "The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary", and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those terms -This challenge also exists in existing approved standards, IRO-010 (currently mandatory) and TOP-003-2 (approved by BOT, awaiting FERC decision). If the RC or TOP make a request for that model in their data specifications, then the GOP (or other entity) must submit those models to the RC and TOP. The SDT ought to address the question, is there a Reliability Related need to ensure that proprietary models gathered at the TOP or RC level be shared across the interconnection. In the Planning Horizon, there is too much inaccuracy in other variables that the effect of the lack of proprietary models cannot be separated from the influence of those other variables; hence, the question ought to be answered from an Operating Horizon perspective. Does the lack of these proprietary models cause a benchmark of Operating Models to actual events to be unacceptably innacurate? -The proposed standard requires the submission of short circuit data for planning models. This data has limited utility in planning studies.
No
PacifiCorp supports the following comments: How are the PC's going to validate data, by range checking or in a power flow? With EMS data? Is there an EMS case that works in PSSE? The proposed standard does not provide any criteria or thresholds for use in determining whether a planning model is adequately validated. In the event that a model is determined to inadequately validated, the proposed standard does not provide a procedure for the PC and equipment owner to resolve issues with the model. Will the PC be required to report poorly validated models to the RRO? Many models are built for non-coincident peak time frames. As such, there would be many issues with trying to validate for a real-time event. The PC is not a real time entity. If the RC is required to provide data to the PC, PacifiCorp affirms that the wrong entity is tasked with performing the validation of data. The planning horizon models represent future system conditions, and validation of these models would likely occur after a given planning model has been retired. The PC has no obligation to verify data once it leaves its hands (i.e. sent to the ERO designee). The wrong model is being validated. By definition, Planning Horizon models cannot be accurate due to forecast error; hence, Operating Horizon models should be validated by the RC rather than Planning Horizon models being validated by the PC. After all, in order to validate a Planning Horizon model to a past event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an Operating Horizon model as a first step. [Frank Gaffney Florida Municipal Power Agency] The proposed standard has overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis. [Frank Gaffney Florida Municipal Power Agency] The models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator. [Frank Gaffney Florida Municipal Power Agency]
Group
Florida Municipal Power Agency
Frank Gaffney
No
Although FMPA appreciates the efforts of the informal development process, FMPA disagrees with the

construct of the proposed SAR and proposed standards. Below are the primary reasons for our Negative vote for both MOD B and MOD C projects, which are described in more detail below. 1. The wrong model is being validated. By definition, planning models cannot be accurate enough to benchmark to operational reality due to forecast error; hence, operating horizon models should be validated by the RC rather than planning horizon models being validated by the PC. After all, in order to validate a planning horizon model to a real event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an operating horizon model. 2. The proposed standard may have overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis 3. In order to relieve this overlap, MOD standards (which FMPA believes are unnecessary and are candidates for P81) should be limited to planning horizon data that differs from operating horizon data. 4. Hence, standards are not needed for Planning Horizon and planning data can be gathered equally efficiently or cost effectively through data requests (e.g., modifications to GADS, TADS, DADS) 5. The proposed standard puts entities in a position of choosing between not complying with the standard, or not complying with a Confidentiality Agreement STANDARDS ARE ALREADY IN PLACE FOR OPERATING HORIZON MODELING Standard TOP-002-2, R19 states: “Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations” (emphasis added). This requirement has been mapped to TOP-003-2 in the new version of the TOP standards filed at FERC in April and awaiting FERC’s decision. R1 of that standard states: “Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.” For operating horizon load forecasts, TOP-002-2, R3 states: “Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.” This requirement has also been mapped to TOP-003-2. IRO-010-1, R1 states: “The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area …” Hence, it is clear that the MOD standards in question should be solely for the Planning Horizon and should not be for the Operating Horizon to eliminate duplication. If the intent is to have the MOD standards apply to the Operating Horizon, then there would be multiple standards governing the same activity and FMPA would propose that the SAR be changed to modify IRO-010-1 and TOP-003-2 as part of this effort to eliminate confusion and double jeopardy. STANDARDS ARE NOT REQUIRED FOR PLANNING HORIZON MODELING The purpose of the SAR starts with a false assertion, that planning studies “depend on accurate mathematical representations of transmission, generation, and load”. FMPA takes issue with the term “accurate”. Planning models by definition cannot achieve the level of accuracy that the ad hoc team seems to desire because they forecast the future. Recognizing that most transmission planning models represent a single representative moment in time: • To accurately model load, we must know the weather (e.g., how much air conditioning load is on), we must know the time of day, the day of the week, the season, we must forecast macro- and micro-economics to predict load growth both at the macro level and by substation, we must know what types of devices are operating on customer’s premises (e.g., variable speed drives, compressors, motors, etc.) to develop an “accurate” representation of load dynamics, and numerous other variables beyond anyone’s control. Load modeling cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. • To accurately model generation, we must predict fuel prices to know what is dispatched (e.g., a dispatch order, as discussed in the draft SAR, is not “accurate”, who would have predicted that “fracking” would have caused gas combined cycle to be dispatched before coal?), we have to predict maintenance cycles and forced outages years in advance, we have to predict the weather because output of gas turbines change significantly with ambient temperature and humidity. We have to predict the impacts of clean air legislation and other environmental legislation on economic dispatch order. For renewables, we have to predict the weather, e.g., how much wind is blowing, how much sun is shining. And many more variables beyond anyone’s control. Generation cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. • To accurately model transmission, we must depend on transmission owners meeting their construction schedules, we are dependent on the moisture in the soil for accurate zero sequence impedance calculations of transmission lines, and other variables beyond our control. Although we have more certainty that the transmission system will be as we predict in the next few years than we do for load and generation, FMPA has direct experience of a major transmission line being cancelled dramatically impacting the study area. Transmission cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. Planning is an important component to reliability, but the goal of planning is not about accuracy. The goal of planning is to study a variety of possible futures, using a variety of types of studies at the choice of the planner, such as scenario analysis and reasonable worst case assessments as is embedded within the TPL standards, or stochastic analyses as are typically used for resource planning, to gain reasonable assurance that we are planning a system that can be reliability operated in the Operating Horizon. Spending too much effort on underlying data is wasted because the inaccuracies inherent in forecasting the future overwhelm other inaccuracies. For instance: • Whether a major generator is on-line or not overwhelms a data error for that generator • Whether the wind is blowing or not overwhelms the value of accurate stability models for those generators • Whether gas is at $3 / MMBtu and gas dispatches before coal, or $10 / MMBtu and coal dispatches before gas overwhelms a dispatch order provided • Whether a new major line gets built or not overwhelms a small error in impedance of that line. • And so on. Hence, there is no reliability related need for the level of "accuracy" desired by the ad hoc team in the Planning Horizon (there is a need for accuracy in the Operating Horizon, see prior section and requirement R19 of TOP-002-2 that requires accurate computer models). In the Planning Horizon, the best that we can do is gather entities best forecasts of the future. Mandatory data requests, such as modifications to DADS, GADS and TADS, are sufficient to gather that planning data and no standard is needed for the Planning Horizon. For Order 693 directives and Order 890 directives purposes, mandatory data requests are equally efficient or effective as a standard for planning horizon data. VALIDATION SHOULD BE DONE BY THE RC ON OPERATING HORIZON MODELS, NOT THE PC ON PLANNING HORIZON MODELS As described in the previous sections, Planning Horizon models cannot be accurate enough to validate. Operating Horizon models are the models that ought to be accurate enough to validate, especially the real-time, current day and next day models (seasonal models will lose accuracy). Hence, the models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator. There ought to be a feedback mechanism from the accurate Operating Horizon models to the Planning Horizon models, but that feedback mechanism does not require a standard. THE STANDARD PUTS ENTITIES IN A DILEMMA OF CHOOSING BETWEEN NOT COMPLYING WITH A STANDARD OR NO COMPLYING WITH CONFIDENTIALITY AGREEMENT(S) FOR SOMETHING THAT MAY NOT BE TECHNICALLY JUSTIFIED The SAR goes to great length to describe a purported problem with obtaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement. In an apparent attempt to avoid the need for a technical justification, the SAR states: "(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection." As described previously, the Planning Horizon is strewn with similar unknowns that we cannot know, and this statement alone is not technical justification. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider if these models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: "(p)roprietary models with details hidden from the user ('black box' models) or those models that cannot be shared across the Interconnection are not acceptable." How will the terms of the CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR's claim that: "The Generator Owner must also arrange to give the

proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary", and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those terms. Such a situation is not acceptable. If the proprietary models are determined to be important, then an effort to reverse engineer models is an alternative. For instance, a project to work with EPRI or similar research institute to develop models for wind turbines from major wind turbine vendors in a laboratory environment could be done presumably without violating any agreements. Such models could then become public domain and used within the Interconnection models. As another alternative, an effort to work with the vendors of the power system analysis software to allow confidential "black box" models to exist within the software itself so that the confidential model is not shared across the Interconnection when the model is shared, but is used within the Interconnection model, but kept confidential within the software, is another alternative. Our interpretation is that the SAR's assertion that "black box" models are unacceptable is because there is no such ability within the existing software; and hence, the models cannot be shared across the Interconnection.
No
Please refer to response in question 1
Please refer to response in question 1
No
Please refer to response in question 1
Group
Oklahoma Gas and Electric Co
Terri Pyle
No
Yes
OG&E requests that the drafting team consider the following rewrite of the SEVERE VSL for R2: The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them in greater than 75 calendar days. Or, the Planning Coordinator did not provide its data requirements at all.
No
Planning models in essence are not accurate and it is based on a forecast at a particular point in time. Therefore, it is our concern that we are trying to validate the planning models against actual system responses. Actual system responses may be very different than the planning models. A variety of factors plays a role in determining the actual system responses – maintenance schedules changed, planned projects delayed, etc. We also have a concern regarding specifically which models are to be validated against the real-time data. This should be specifically spelled out in the standard. In addition, R1.3 does not provide a guideline on how large the discrepancy needs to be. Does it have to be the same margin of error for all seasons or vary by season? What is the acceptable amount of discrepancy? Transmission Operator is missing in the 6th line of M2. M2 should read '…or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation…'.
Group
Duke Energy
Michael Lowman
Yes
Table 2 of the SAR identifies the RC and TOP for deliverability for data. However, we do not see where

in MOD-032 this delivery of data occurs. Duke Energy suggests adding the GOP if short term limits are included in the scope of this standard. Duke Energy suggests rewording the second paragraph under SAR information to: “Generator Operators must provide accurate model data of their systems during the interconnection process and when changes to equipment are made during the life of the plant” for added clarity.
Yes
Duke Energy believes that Interchange Coordination between neighboring TSPs should be identified in Attachment 1. In addition, we believe that Attachment 1 should also include a similar data requirement to load for generator “in service status” and possibly a footnote or parenthetical that says the generation dispatched should be representative of expected real time operation of generation resources for the modeled conditions. Lastly, Duke Energy questions the reliability based need for R5.2. Duke Energy believes that the scope of the documentation should be narrowed to only include major data modifications that could affect the model. To include all data modifications would create an unnecessary administrative burden on the PC. Another suggestion would be to add a requirement that the ERO or its designee request this type of documentation, similar to R4, as part of the model building process.
Yes
Duke Energy suggests rewording R1.1 as follows: “Validate its portion of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other Real-time data sources to check for discrepancies that the Planning Coordinator determines would warrant such an analysis at least once every 24 calendar months through simulation.” Duke energy suggests increasing the time allowed between steady-state and dynamic simulations in R1.1 and R1.2 from once every 24 months to once every 36-60 months. Duke Energy seeks clarification from the SDT on what constitutes a “local” event in a dynamic local event. Is the “local” event regional or entity specific? We also seek clarification on how an auditor measures whether a PC has done enough validation to satisfy compliance obligations in R1. Duke energy suggests rewording R2 as follows: “Each Reliability Coordinator 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 that has indicated a reliability-related need for the data within 30 calendar days of a written request. Examples of data include, but are not limited to:” - state estimator case(s) - other Real-time data (including disturbance data recordings) necessary for actual system response validation.
Individual
Larry Brusseau
MAPP
Yes
This process appears to be out of synch. Approving a standard without approving the SAR first. The informal process seems to be rushing the process without due diligence.
No
Requirements 1 from both MOD-014 and MOD-015 have not been mapped to the new proposed standard. Developing power flow and dynamic models are needed to preform the needed studies for FAC, PRC, and TPL standards. This is a gap in the MOD standards. This is gap is which entity is developing models? There needs to be a standard directing an entity to develop models or a change in the ‘Rules and Procedures’. Specific comments/questions below: • Has ERAG acknowledged that they will be getting 51 raw data sets from the PCs (i.e. unsolved, incomplete data)? • ERAG is not in the functional model and not subject to compliance, can the PC’s be responsible for modeling issues? • The PC is really just a middle-man for the data, so why even be in the process? What value is there? • If one or more regions gest out of building models, is ERAG still the one to aggregate them? • If ERAG is the regions and they build the power flows is there still a conflict of interest? MAPP as a PC has not been involved with the model development or data collection. We do not have the infrastructure to develop models; We need a long implementation time to put these facilities in place. Not everyone uses the PTI product ‘model on demand’, as the tool the TO could use on behalf of the PC. The first suggestion is a modification to the R1.5 text “R1.5. Specification of the case types or

scenarios to be modeled (for steady state and dynamic data sets); and…". The second suggestion is a modification to the R2 text, replace "…in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures." with "…in it s planning area within 30 calendar days of any data requirements and reporting procedure modifications.". R2. Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures. Issue: Requirement 2 above is based on a "written request" for data requirements and reporting procedure while the comment states this would be expanded to modifications to data requirements and reporting procedure. We interpret this to mean that whenever there is a "modifications" to data requirements and reporting procedure, the entity will be required to resend this information to each requester within 30 days. Recommend the term "modifications" be removed.
We request clarification of item 4 of the Steady-State portion of Attachment 1 in MOD-032-1: 4. AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO] Why does the drafting team see the need to explicitly model series capacitors and reactors? This equipment is usually not breakered and thus from a contingency standpoint, is part of the line that it's connected to. Explicitly modeling series reactors and capacitors would provide misleading results when performing N-1 contingency analysis. The SAR goes to great length to describe a purported problem with gaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement In an apparent attempt to avoid the need for a technical justification, the SAR states: "(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection." The Planning Horizon is strewn with similar unknowns that we cannot know (load models, generator dispatch, transmission construction), and this statement alone is not technical justification. However, accurate models may be needed for the Operating Horizon. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider. These models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: "(p)roprietary models with details hidden from the user ('black box' models) or those models that cannot be shared across the Interconnection are not acceptable." How will the terms of such a CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR's claim that: "The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary", and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those . This challenge also exists in existing approved standards, IRO-010 (currently mandatory) and TOP-003-2 (approved by BOT, awaiting FERC decision). If the RC or TOP makes a request for that model in their data specifications, then the GOP (or other entity) must submit those models to the RC and TOP. The SDT ought to address the question, is there a Reliability Related need to ensure that proprietary models gathered at the TOP or RC level be shared across the interconnection. In the Planning Horizon, there is too much inaccuracy in other variables that the effect of the lack of proprietary models cannot be separated from the influence of those other variables; hence, the question ought to be answered from an Operating Horizon perspective. Does the lack of these proprietary models cause a benchmark of Operating Models to actual events to be unacceptably inaccurate?
No

How are the PC's going to validate data, by range checking or in a power flow? With EMS data? Is there an EMS case that works in PSSE? Many Models are built for non-coincident peak time frames, there would be many issues trying to validate for a real-time event. The PC is not a real time entity; we would be validating the RC models (RC required to provide data to PC), seems the wrong entity is doing the validation. The PC has no obligation to verify data once it leaves its hands (i.e. sent to the ERO designee). The wrong model is being validated. By definition, Planning Horizon models cannot be accurate due to forecast error; hence, Operating Horizon models should be validated by the RC rather than Planning Horizon models being validated by the PC. After all, in order to validate a Planning Horizon model to a past event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an Operating Horizon model as a first step The proposed standard has overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis The models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator Please separate the Standards into separate ballots.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
Yes
1. The first suggestion is a modification to the R1.5 text "R1.5. Specification of the case types or scenarios to be modeled (for steady state and dynamic data sets); and…". Since FERC Order 890 in February, 2007, much work has gone into the development of reliability standards, including requirements pertaining to short circuit data. Inclusion of short circuit data in the MOD-032 standard appears duplicative and will create an administrative burden to the industry that is not warranted. ATC recommends that the SDT revisit the impetus for including short circuit data in the proposed standard. While addressing the proposed MOD standards, the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS) has stated that providing short-circuit data should not be required for assembly into an interconnection-wide case, but there should be requirements for sharing amongst neighboring entities. That is a noble objective that ATC supports; however, neighboring entity coordination is covered under PRC-001 and will be expanded under the proposed PRC-027. Other standards, such as FAC-002 and the future TPL-001 also include requirements relating to short circuits. 2. The second suggestion is a modification to the R2 text, replace "its planning area within 30 calendar days of a written request for the data requirements and reporting procedures." with "…in its planning area within 30 calendar days of any data requirements and reporting procedures modifications.".
Yes
NERC posted this project for comments for both MOD-032-1 and MOD-033-1, and at the same time, set up one ballot to cover both MOD Standards which ATC feeels is a poor practice. Posting for one ballot does not allow the entity to favor one while not the other and visa versa. For future postings, please split the two MOD Standards into two separate ballots.
Individual
Laurie Williams
PNM Resources, Inc.
Yes
PNM recommends that NERC assist the Regions with defining what PC "areas" are. In the western United States, in areas that are not part of ISOs, the PC concept has not been clearly defined for

entities and the Region has not provided any specific guidance on what exactly constitutes a PC 'area.' Lack of specific guidance will create reliability gaps and audit difficulties as PC responsibilities increase.
Yes
PNM cast a negative ballot based exclusively on the language on R5.2 and the corresponding language related to R5.2 in the VSL. PNM would like the standard to clarify what "data modifications" would trigger the requirement to report to the ERO under this requirement. Additionally, the VSL requires "The Planning Coordinator submitted the required data to the ERO or its designee but failed to include documentation and reasons for any data modifications", which implies that any single data modification, regardless of how minor, must be explicitly reported to the ERO and that report must be accompanied by the reason(s) why the data item was changed. PNM seeks to clarify R5.2 by perhaps qualifying the data modifications that would be significant enough to trigger 5.2 reporting. PNM anticipates that the ERO/RRO reporting of "modifications" could be time consuming for both entities reporting and the ERO/RRO receiving this information and in many cases not contribute to increasing the reliability of the BES. PNM suggests a qualifier that would eliminate load changes at individual busses and perhaps other items that should not have to be individually detailed.
Yes
None
Individual
Spencer Tacke
Modesto Irrigation District
No
1. In MOD-032, there is a blurring of responsibilities between the Transmission Planner and the Planning Authority (i.e., Planning Coordinator). As many utilities have no officially designated Planning Authority (Coordinator), this could be a problem. 2. The specific model data required (R1.1) is apparently detailed in Attachment 1, which does not seem to exist.
No
1. In MOD-033, there is a blurring of responsibilities between the Transmission Operator and the Planning Authority (Coordinator). As many utilities have no officially designated Planning Authority (Coordinator), this could be a problem. 2. The specific requirement (R1.1) for use of a State Estimator or equivalent, is not practical, as many smaller utilities cannot afford one nor justify the need for one in their normal day-to-day operations. 3. The specific requirement (R1) that the Planning Coordinator (Authority) "validate model data used for steady state and dynamic analyses for its planning area against actual system response" is not always possible, as the local planning area simulated response is not only dependent on the accuracy of the local planning area equipment models, but also on the accuracy of the adjacent planning areas equipment models, too.
Individual
Teresa Czyz
Georgia Transmission Corporation
No
No
R1 – At present, data requirements and reporting procedures have already been written by the RRO, based on ERO requirements, for consistency. Replacing the RRO with the PC in the standard raises concerns. The responsibility for each PC to develop their own model data requirements may result in

inconsistent data being submitted to the ERO. It is preferrable that the RRO remain in the process. R3 – With each PC developing their own model data requirements, there is concern once again with consistency in the data submitted by the entities under this requirement. R5 – We believe the EROs should be responsible for providing model data requirements as stated in R1. The EROs are responsible for creating the Interconnection models. Therefore, it seems reasonable that the EROs set the model data requirements to facilitate a process that would not create seams issues which could occur with the increase of PCs that would be involved.
Yes
R1.1 – Most state estimators have been developed based on the planning model. Therefore, it should be rare for any discrepancy to occur. It appears that this is more of an operational function to validate the accuracy of the state estimator. The requirement also does not define what data is to be validated. R1.2 – The requirement does not define what data is to be validated. The first sentence should also include “by comparing it to actual system behavior” (as was done in R1.1) to specify how the data is compared. The MOD standards also need to assign responsibilitites and requirements for data validation and data submittal by GOs, particularly for dynamic models. If the generator model is not correct, the planning model will not be correct.
Group
BANC & SMUD
Joe Tarantino
No
Yes
SMUD is submitting a Negative positions for both of the Modeling Data Standards (MOD B). Although we believe the condensing of the MOD-010 thru MOD-015 standards are a movement in the right direction the concerns are such that we feel validate the Negative position. MOD-032-1 –Power System Modeling & Analysis Salient Issues: • For R1 the Planning Coordinator should be replaced with correct wording that allows for a regional process to be implemented. This would allow for a single reporting procedure by multiple PC/PAs to be established among entities providing data consistency necessary for system modeling. • R2 should also be driven by the regional process of R1. The data request hat is required for modeling should come from the PC who is responsible for ensuring accuracy of modeling parameters and should work with the appropriate entities who have that data. This would allow the modeling of data to be populated in the models utilized by the PC/TOP for their system studies. • R4 should be reconstructed such that it requires the PC/PA and the owner of a facility that requires modeling to identify acceptable modeling characteristics for the program utilized by the PC/PA. If the owner submits a unique block diagram that may not directly correlate to the available model in the PC’s program.
Yes
SMUD is submitting a Negative positions for both of the Modeling Data Standards (MOD B). Although we believe the condensing of the MOD-010 thru MOD-015 standards are a movement in the right direction the concerns are such that we feel validate the Negative position. MOD-033-1 –Steady-State & Dynamic System Modeling Validation Salient Issues: • For R1 the overarching steady-state and dynamic validation should be conducted at a regional level for regional modeling validation. o Having individual PC evaluate their own bubble misses the impact that would be identified on large-scale system performance. o Provide for collaboration among multiple industry experts o A 24-month period is too restrictive, suggest a 5-year period. o For R1.3 there is not specific performance requirement identified leaving the measure for “too large” of system performance subjective. • We support a regional modeling validation that requires PC & TP or other appropriate entity to participate in the regional review that would include performance measures in the sub-regions. • Individual PC/PA/TP performance should be limited to steady-state validation. Dynamic validation would be covered under the participation in the regional validation requirements.
Group

ACES Standards Collaborators
Ben Engelby
Yes
(1) We recommend that the drafting team consider revising its approach to MOD B. NERC recently hired industry experts to perform an all-encompassing review of each standard that is currently in effect. According to the report titled “Standards Independent Experts Review Project: An Independent Review by Industry Experts,” there are numerous MOD standards that are recommended to be combined with the TPL standards. The MOD B standards were recommended to be included in a new construct, where requirements would be developed to “assess transmission future needs and develop transmission expansion plans – not operational planning.” We strongly recommend that the drafting team review these recommendations and consider revising the draft SAR to take into account the TPL standards and to remove references to operational planning. This will greatly reduce the compliance burden of maintaining evidence for both TPL and MOD standards. We are unable to support this standard until the team proposes these changes in the SAR or justifies why the recommendations should not be acted upon at this juncture. (2) We are concerned that the informal development process that was originally contemplated has gone off course. The original plan that was announced to industry was to have an informal development team create a proposal for a standard, who would then pass the work to a formal standard drafting team to continue the development process. This is not what has occurred. Instead, the informal development team drafted the initial draft standard prior to the SAR being approved through the formal process. The informal development process should not circumvent the NERC Rules of Procedure. (3) We question the value in posting the draft standard with the SAR. What good is the SAR posting if a standard has already been developed? This gives the impression that the Standards Committee has already determined the need for the standard and eliminates the opportunity for stakeholders to provide comments for consideration. We urge NERC to pay close attention to its Rules of Procedure and the Standard Process Manual to avoid deviations and setting precedent that could be challenged in the future. While we agree in principle with the consolidation of the numerous requirements in this project, the Standards Process Manual still must be followed. (4) We are also concerned that there was a deviation in the standards process manual regarding the selection of the drafting team. The informal team should not have been appointed as the formal standard drafting team without soliciting nominations first, as this creates the perception of NERC hand selecting drafting team members, which is not in accordance with the standards development manual. The nomination period began after the draft standard was posted, which clearly shows the work of the ad hoc team was to develop the draft standard instead of vetting the issues with industry and having a proposal outlined in the SAR. The initial draft standard should be the work of the formal standard drafting team. We doubt that there was sufficient time for any new drafting team members that did not participate in the informal development process to thoroughly review the language in the draft standard. The method of developing the initial draft should comply with the NERC Rules of Procedure in the same manner as all other phases of formal standard development.
No
There was not a field to enter comments for question 2 on the unofficial comment form. Please see our comments in question 3.
(1) We have concerns with Requirement R1. R1 states: “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area...” The phrase “in conjunction with each of its Transmission Planners” is not a defined or measureable action. Moreover, the phrase is subjective and does not clearly state which Transmission Planners are applicable to R1. This could also lead to overlap in planning areas and may suggest a shared responsibility among functions. We recommend deleting the phrase “in conjunction with each of its Transmission Planners.” This will make the requirement clearly apply to the PC and avoid the confusion of whether the requirement applies to the TP. (2) Requirement R1, parts 1.1 through 1.6: Why is this criteria included in the requirement and not in an attachment? We recommend adding “where confidentiality agreements allow” for part 1.3. There are several requirements that take this approach, including TOP-002 R3, R4 and R16, to protect confidential information. (3) Requirement R3. We believe this requirement could be the only requirement in the standard. Point to the attachment of the types of data that is required and make the standard a straightforward process. This could still satisfy the FERC directives. (4) Requirement R4. This requirement is overly complicated. The feedback loop does

not need to be a requirement. According to the NERC Compliance Operations guidance document, “the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified.” There is no need to have a feedback loop, only that the data was delivered as specified. Further, this requirement could meet the P81 criteria. We recommend striking R4. (5) In addition, we appreciate the supplemental information provided in this posting. We would like to see compliance guidance on each requirement in future postings, or a draft RSAW to supplement the standard.
No
There was not a field to enter comments for question 4 on the unofficial comment form. Please see our comments for MOD-033-1 in question 5.
(1) We do not believe a standard is needed for validation. We suggest that the drafting team consider other alternatives to approaching the FERC directive instead of developing a validation standard. (2) Requirement R1. We believe it would be helpful to clarify the meaning of the word “validate.” Is a Planning Coordinator compliant if it has a modeling program “designed to represent conditions” or must the Planning Coordinator have a program that duplicates or can be made to duplicate actual conditions? The former approach does not punish the Planning Coordinator if the program fails to meet an auditor’s view of accurate results. The latter approach may result in Planning Coordinators being required to simulate a state that cannot be duplicated. Also, Part 1.1 seems to imply validate means compare. A PC could compare their model to real-time conditions and determine that there are large differences or small differences. Since no model will ever represent actual conditions perfectly, how small do the differences have to be? We do not advocate that the standard should highlight mandate specific thresholds but highlight this point because it will lead to inconsistent compliance application. Two auditors may look at the same validation data and have different opinions on whether the differences are small enough to consider the model validated. (3) The validation process needs to consider that most of the models that a PC develops are future models and, therefore, should not be validated against real-time system conditions since system topology, load levels and generation patterns can be quite different. Validation should only focus on near-term models. (4) Requirement R1, part 1.1. We would like clarification that entities are not required to own a state estimator to be in compliance with part 1.1 and will not be required to purchase and stand up a state estimator. The language states, “represented by a state estimator case…” We appreciate additional clarification, perhaps in the technical discussion section, that specific alternative sources would be acceptable. (5) We suggest that all references to state estimators should be removed from the standard. Validation should be performed against an appropriate data source. State estimators can certainly be good data sources but care must be taken in using them to validate models because they do not preserve energy balance at a bus as a power flow model does. Since they are a statistical fit of measurements to a transmission model, the errors at each bus can accumulate and lead to larger errors, especially in large interconnection models. Thus, we suggest that the use of state estimators should not be suggested explicitly because real-time measurements may be a better data source. (6) Requirement R2. The measure and requirement are mislabeled. The requirement is labeled as “M2” and the measure is labeled as “R2.” (7) Requirement R2. We would like the drafting team to provide a rationale why it chose 30 days for an appropriate timeline. There is no technical justification listed. (8) Requirement R2. This requirement is subject to Paragraph 81 criteria because it relates to reporting obligations to other responsible entities. The P81 criteria states, “B4. Reporting: The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.” Furthermore, the RC should be more than willing to provide the necessary data to ensure models are validated. The RC often inherits these models for use in operational planning. (9) Thank you for the opportunity to comment.
Individual
Clay Young
SCE&G
No

No
R1 We have concerns regarding replacement of the RRO with the PC in the standard. In addition, with the learning curve time associated with testing and forwarding to those finalizing models the opportunities with seams issues seem significant and possibly on-going with the increase of PCs involved. Therefore, it would preferable to maintain the Region in the process as at present. R2. It appears that without a uniform data standard the scope of the data may not be uniformed. Using the Region as a collection point has merit in ensuring that the data requirements are consistent. R3. The concern centers on consistent and comparable data submitted. Removing the Regions as the collectors may necessitate development of a guideline manual that all accept to ensure that data is consistent. R5. The SDT is requested to include clarification language that the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection models, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection models, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection models and each will provide a procedural manual for their area to ensure data submittal is consistent.
Yes
The SDT is requested to review the other MOD standards to ensure that GOs are covered and required to submit data when requested.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
Section 4.1, Applicability - The Functional Entities should be listed in a non-plural form for consistency with other NERC standards.
Yes
R1. / R5. 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 multi-regional (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. R2. The Transmission Planner should be added to the list of functional entities that can request data requirements and reporting procedures from the Planning Coordinator. The rationale statement for R2 recognizes that changes in ownership can occur. If ownership of transmission assets changes, the Transmission Planner for those assets may also change. The “new” Transmission Planner for those assets may not have worked in conjunction with the Planning Coordinator to develop the data requirements and reporting procedures under R1.
Yes

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.
Individual
Christina Conway
Oncor Electric Delivery Company LLC
No
No
R1. Oncor Electric Delivery supports the idea of combining the respective data submittal standards into a single data submittal standard. However, Oncor believes a shared approach between the Planning Coordinator and Transmission Planners to determine data requirements would be more thorough and beneficial to all parties. Oncor supports the verbiage indicating that the Planning Coordinator is to determine modeling requirements “in conjunction with each of its Transmission Planners. ” However, Oncor is concerned that this verbiage is insufficient to address the Transmission Planner’s concern that a Planning Coordinator may dictate data requirements without consulting those whom deal with the data for their particular portion of the grid. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator’s unilateral determination of requirements to be imposed upon various entities. Furthermore, the verbiage in requirement R2 stating the “Planning Coordinator shall provide its data requirements…” raises concerns that the Planning Coordinator may act without consulting the Transmission Planners. Oncor recommends inserting language indicating that the data requirements be developed together between the Planning Coordinator and the Transmission Planners. R1.1 Based upon the comments provided for Requirement R1, above, Oncor Electric Delivery believes that the Attachment 1 table is too prescriptive and needs to be modified to display those data requirements agreed upon by the Planning Coordinator and the respective Transmission Planners. R4. Oncor Electric Delivery recognizes that data may need to be updated in a timely manner so that the changes can be accurately modeled; however, the 30 calendar days response period may not be sufficient. If the Planning Coordinator is not agreeable to a longer response period, the responding entity may be found in non-compliance with this requirement. The response time should be mutually agreed to between the parties, and should not be dictated by the standard.
Yes
N/A
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
No
No
CenterPoint Energy appreciates the efforts of the SDT and agrees with the approach of consolidating existing MOD standards 011 through 015 into one standard. Our specific concers are detailed below: R1. CenterPoint Energy supports a collaborative approach between the Planning Coordinator and Transmission Planners to determine data requirements and appreciates the SDT’s attempt to incorporate this approach by indicating that the Planning Coordinator is to determine modeling requirements “in conjunction with each of its Transmission Planners. ” However, CenterPoint Energy is concerned that this verbiage is insufficient to address the concern that a Planning Coordinator may

unilaterally dictate data requirements. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator's unilateral determination of requirements to be imposed upon various entities. Furthermore, some entities affected by the requirements, such as transmission and generation owners, would not have an opportunity to be represented in an open and transparent stakeholder process to weigh the relative merits against the feasibility, cost, and burden of proposed new requirements. In addition, the language in R2 stating the "Planning Coordinator shall provide its data requirements…" raises the concern that the Planning Coordinator may act alone. As an alternative, CenterPoint Energy recommends inserting "mutually agreeable" as follows: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop mutually agreeable steady-state, dynamics, and short circuit modeling data requirements… R1.1 CenterPoint Energy believes that the Attachment 1 table is 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. CenterPoint Energy also believes that the Dynamics data requirement No. 5 "Demand" data requirement is vague and needs to be clarified. Making these modifications will provide the consistency for which the SDT is striving but will relieve the unnecessary compliance burden of the current draft. R4. CenterPoint Energy recognizes that data may need to be updated in a timely manner so that the changes can be accurately modeled; however, the 30 calendar days response period may not be sufficient. If the Planning Coordinator is not agreeable to a longer response period, the responding entity may be found in non-compliance with this requirement. The response time should be mutually agreed to between the parties, and should not be dictated by the standard.
Yes
Individual
Texas Reliability Entity, Inc.
Texas Reliability Entity, Inc.
No
Yes
Yes
1) TRE believes that each Planning Coordinator, in conjunction with each of its Transmission Planners, must implement a documented process to validate the data used for steady state, short circuit, and dynamic analyses for its planning area against actual system responses, and once errors are identified during the validation process, the errors need to be corrected within 60 calendar days. a. TRE believes MOD-33-1 should be changed to include Short Circuit Model validation in order to ensure the necessary accuracy is achieved in all models included in MOD-32-1. b. Since the validation process in MOD-33-1 includes comparing models built by Transmission Planners to actual system behavior, TRE believes MOD-33-1 should be changed to also apply to Transmission Planners. c. TRE believes that the errors identified during the validation process need to be corrected within a specific amount of time to ensure corrections are timely, so TRE believes MOD-33-1 should be changed to include the requirement to make corrections within 60 calendar days.
Individual
Ed O'Brien
MIodesto Irrigation District
No
No

MOD-032: 1. In MOD-032, there is a blurring of responsibilities between the Transmission Planner and the Planning Authority (i.e., Planning Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific model data required (R1.1) is apparently detailed in Attachment 1, which does not seem to exist.
MOD-032: 1. In MOD-032, there is a blurring of responsibilities between the Transmission Planner and the Planning Authority (i.e., Planning Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific model data required (R1.1) is apparently detailed in Attachment 1, which does not seem to exist.
No
MOD-033: 1. In MOD-033, there is a blurring of responsibilities between the Transmission Operator and the Planning Authority (Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific requirement (R1.1) for use of a State Estimator or equivalent, is not practical, as many smaller utilities cannot afford one nor justify the need for one in their normal day-to-day operations. 3. The specific requirement (R1) that the Planning Coordinator (Authority) "validate model data used for steady state and dynamic analyses for its planning area against actual system response" is not always possible, as the local planning area simulated response is not only dependent on the accuracy of the local planning area equipment models, but also on the accuracy of the adjacent planning areas equipment models, too.
MOD-033: 1. In MOD-033, there is a blurring of responsibilities between the Transmission Operator and the Planning Authority (Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific requirement (R1.1) for use of a State Estimator or equivalent, is not practical, as many smaller utilities cannot afford one nor justify the need for one in their normal day-to-day operations. 3. The specific requirement (R1) that the Planning Coordinator (Authority) "validate model data used for steady state and dynamic analyses for its planning area against actual system response" is not always possible, as the local planning area simulated response is not only dependent on the accuracy of the local planning area equipment models, but also on the accuracy of the adjacent planning areas equipment models, too.
Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy
Yes
This process appears to be out of synch. Approving a standard without approving the SAR first. The informal process seems to be rushing the process without due diligence.
No
Requirements 1 from both MOD-014 and MOD-015 have not been mapped to the new proposed standard. Developing power flow and dynamic models are needed to preform the needed studies for FAC, PRC, and TPL standards. This is a gap in the MOD standards. This is gap is which entity is developing models? There needs to be a standard directing an entity to develop models or a change in the ‘Rules and Procedures’. Specific comments/questions below: • Has ERAG acknowledged that they will be getting 51 raw data sets from the PCs (i.e. unsolved, incomplete data)? • ERAG is not in the functional model and not subject to compliance, can the PC’s be responsible for modeling issues? • The PC is really just a middle-man for the data, so why even be in the process? What value is there? • If one or more regions gest out of building models, is ERAG still the one to aggregate them? • If ERAG is the regions and they build the power flows is there still a conflict of interest? MAPP as a PC has not been involved with the model development or data collection. We do not have the infrastructure to develop models; We need a long implementation time to put these facilities in place. Not everyone uses the PTI product ‘model on demand’, as the tool the TO could use on behalf of the PC. The first suggestion is a modification to the R1.5 text “R1.5. Specification of the case types or scenarios to be modeled (for steady state and dynamic data sets); and…”. The second suggestion is a modification to the R2 text, replace “…in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures.” with “…in it s planning area within 30 calendar

days of any data requirements and reporting procedure modifications.”. R2. Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures. Issue: Requirement 2 above is based on a “written request” for data requirements and reporting procedure while the comment states this would be expanded to modifications to data requirements and reporting procedure. We interpret this to mean that whenever there is a “modifications” to data requirements and reporting procedure, the entity will be required to resend this information to each requestor within 30 days. Recommend the term “modifications” be removed.
We request clarification of item 4 of the Steady-State portion of Attachment 1 in MOD-032-1: 4. AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO] Why does the drafting team see the need to explicitly model series capacitors and reactors? This equipment is usually not breakered and thus from a contingency standpoint, is part of the line that it’s connected to. Explicitly modeling series reactors and capacitors would provide misleading results when performing N-1 contingency analysis. The SAR goes to great length to describe a purported problem with gaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement In an apparent attempt to avoid the need for a technical justification, the SAR states: “(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection.” The Planning Horizon is strewn with similar unknowns that we cannot know (load models, generator dispatch, transmission construction), and this statement alone is not technical justification. However, accurate models may be needed for the Operating Horizon. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider. These models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: “(p)roprietary models with details hidden from the user (‘black box’ models) or those models that cannot be shared across the Interconnection are not acceptable.” How will the terms of such a CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR’s claim that: “The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary”, and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those . This challenge also exists in existing approved standards, IRO-010 (currently mandatory) and TOP-003-2 (approved by BOT, awaiting FERC decision). If the RC or TOP make a request for that model in their data specifications, then the GOP (or other entity) must submit those models to the RC and TOP. The SDT ought to address the question, is there a Reliability Related need to ensure that proprietary models gathered at the TOP or RC level be shared across the interconnection. In the Planning Horizon, there is too much inaccuracy in other variables that the effect of the lack of proprietary models cannot be separated from the influence of those other variables; hence, the question ought to be answered from an Operating Horizon perspective. Does the lack of these proprietary models cause a benchmark of Operating Models to actual events to be unacceptably innacurate?
No
How are the PC’s going to validate data, by range checking or in a power flow? With EMS data? Is

there an EMS case that works in PSSE? Many Models are built for non-coincident peak time frames, there would be many issues trying to validate for a real-time event. The PC is not a real time entity; we would be validating the RC models (RC required to provide data to PC), seems the wrong entity is doing the validation. The PC has no obligation to verify data once it leaves its hands (i.e. sent to the ERO designee). The wrong model is being validated. By definition, Planning Horizon models cannot be accurate due to forecast error; hence, Operating Horizon models should be validated by the RC rather than Planning Horizon models being validated by the PC. After all, in order to validate a Planning Horizon model to a past event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an Operating Horizon model as a first step The proposed standard has overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis The models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator Please separate the Standards into separate ballots.
Individual
Alice Ireland
Xcel Energy
No
Yes
Would like to ensure that the PC's are required to work closely with their members to resolve modeling and modeling data issues. Please consider modifying R2 to require the PC to be responsive similar in concept to what is required in FAC-010-2.1 R5 (except related to model building vs. SOL Methodology). FAC-010-2.1 R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason.
Yes
Concerned that state estimator case or other Real-time data may not contain enough level of detail required to validate the case (e.g. impacts of the low voltage facilities (generators, loads) on the BES).
Individual
Jose H Escamilla
CPS Energy
No
Yes
CPS Energy's specific concerns are detailed below: R1. CPS Energy supports a collaborative approach between the Planning Coordinator and Transmission Planners to determine data requirements and appreciates the SDT's attempt to incorporate this approach by indicating that the Planning Coordinator is to determine modeling requirements "in conjunction with each of its Transmission Planners." However, CPS Energy is concerned that this verbiage is insufficient to address the concern that a Planning Coordinator may unilaterally dictate data requirements. In addition, the language in R2 states that the "Planning Coordinator shall provide its data requirements…" raises the concern that the Planning Coordinator may act alone. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator's unilateral determination of requirements to be imposed upon various entities. Furthermore, some entities affected by the requirements, such as transmission

and generation owners, would not have an opportunity to be represented in an open and transparent stakeholder process to weigh the relative merits against the feasibility, cost, and burden of proposed new requirements. As an alternative, CPS Energy recommends inserting “mutually agreeable” as follows: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop mutually agreeable steady-state, dynamics, and short circuit modeling data requirements… R1.1 CPS Energy believes that the Attachment 1 table is overly prescriptive. Our main concern is in retaining evidence that each particular item has been submitted to the appropriate parties. This is a large amount of documentation to retain to indicate that each item has changed or has not been changed. At a minimum, the table in Attachment 1 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, otherwise, this table should be removed. CPS Energy also believes specific reference to a composite load model should be removed from the Dynamics data requirement No. 5 “Demand”. While we find the composite load model very important in dynamic analysis, we believe the load modeling requirements should be determined at the regional level. Therefore, the table should read as follows: 5. Demand [LSE] (consistent with system load representation and components as a function of frequency and voltage). Making these modifications will provide the consistency for which the SDT is striving but will relieve the unnecessary compliance burden of the current draft. R2. This requirement makes no mention that the Transmission Planner is a recipient of the data requirements, even though they helped in creating them. R4.2 This requirement should be removed as it is redundant to what is required in R3 and R4.1. Also, this requirement strays from data collection and leans toward data validation. M4. In general, this measurement is overly prescriptive and is excessive and cumbersome from a documentation standpoint. The documentation methodology should be determined at a regional level, as requests for new data in one region may be extremely different than in other regions.
Yes
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
No
Austin Energy (AE) appreciates the efforts of the SDT and agrees with the approach of consolidating existing MOD-011 through MOD-015 into one standard. Our specific concerns are detailed below: (1) For Requirement R1, AE supports a collaborative approach between the Planning Coordinator and Transmission Planners to determine data requirements and appreciates the SDT’s attempt to incorporate this approach by indicating that the Planning Coordinator is to determine modeling requirements “in conjunction with each of its Transmission Planners.” However, AE is concerned that this language does not address the concern that a Planning Coordinator may unilaterally dictate data requirements. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator’s unilateral determination of requirements imposed on various entities. Furthermore, some entities affected by the requirements, such as Transmission and Generation Owners, would not have an opportunity to be represented in an open and transparent stakeholder process to weigh the relative merits against the feasibility, cost, and burden of proposed new requirements. In addition, the language in R2 stating the “Planning Coordinator shall provide its data requirements …” raises the concern that the Planning Coordinator may act alone. As an alternative, AE recommends inserting “mutually agreeable” as follows: “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop mutually agreeable steady-state, dynamics, and short circuit modeling data requirements …” (2) For Requirement R1.1, AE believes the Attachment 1 table is too prescriptive and should 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. AE also believes the Dynamics data requirement No. 5 “Demand” data requirement is vague and should be clarified. Making these modifications will provide the consistency for which the SDT is striving but will relieve

the unnecessary compliance burden of the current draft. (3) For Requirement R4, AE recognizes that data may need to be updated in a timely manner so the changes can be accurately modeled; however, the 30 calendar days response period may not be sufficient. If the Planning Coordinator is not agreeable to a longer response period, the responding entity may be found in non-compliance with this requirement. The response time should be mutually agreed upon by the parties and should not be dictated by the standard.
No
AE believes that a requirement to validate dynamic models at least once every 24 calendar months uses an inappropriate timeframe. AE suggests that Requirement R1, Part 1.2 be changed to “Validate its portion of the system in the dynamic models at least once every 60 calendar months through simulation of a dynamic local event. Complete the simulation within 12 calendar months of the local event.”
Individual
Richard Vine
California Independent System Operator
No
Yes
For this Standard to work effectively, it is essential for the PC to know all registered entities (TOs, GOs, TPs, DPs, LSEs, TSPs, RPs) within its purview, and vice versa (entities need to know who their PC is.) It would be helpful if NERC or the Regional Entity would provide such a mapping (listing of registered entities (TO, GO, TP, DP, LSE, TSP, RP) within their purview) to the PCs on an ongoing basis so that PCs and data submitting entities can stay current on their obligations.
Yes
It would be helpful to clarify the meaning of the word "validation". Is a PC compliant if it has a program "designed to represent conditions" or is the PC expected to have a program that duplicates or can be made to duplicate actual conditions? The former approach does not penalize the PC if the program does not meet an Auditor’s view of accurate results. The latter approach may result in PCs being required to simulate a state that cannot be duplicated.
Group
Southern Company: Southern CompanyServices, 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
Yes
On R1: Uniformity of the data request form is desirable. R1 data requirements should be sensitive to the life cycle of the generator (age, data availability for pre-1970 units, units in various stages of project development, planning, and start up), or to unconventional data requests that would require reverse/extensive engineering techniques to fulfill. R2 is purely administrative and should be eliminated. The PC should simply deliver the data requirements and reporting procedures to the BAs, GOs, TOs. etc. once they have developed or revised them. Attachment 1 should provide additional details of precisely what "minimum" data is required - for example, on the generator which time constants and which reactances are required. For the VSL on R3, perfect data submission is in violation (0% missing/unformatted/late is less than 25%) - please correct. Consider some minimum level of data shortage/formatting/tardiness being acceptable rather than instituting a "zero tolerance"

position - say 5% up to 25% is the Lower VSL. A zero tolerance for a VSL seems inconsistent with the NERC Reliability Assurance Initiative and risk based compliance and enforcement approach. For R4.2 - an explanation with a technical basis for maintaining the current data should be allowed here too (like R4.1). Attachment 1, steady state, item 3c - station service auxiliary load data should be restricted to normal plant configuration for the GO Attachment 1, steady state, item 3d - please define what is meant by "regulated bus". Attachment 1, steady state, item 3e - is this the voltage schedule? Attachment 1, steady state, item 3f - what value is the % ownership to the model? Attachment 1, steady state, item 3h - please clarify what this means for generating units. Attachment 1, steady state, item 6g - please explain what this rating is. Attachment 1, steady state, item 9 - we believe that there should be a requirement for the PC to provide technically based reasons for expanding the data request beyond what is listed in Attachment #1. (Requirement 1, Attachment 1 - steady state, item 9). We recommend R5 be removed from the draft standard altogether and that the PC deliver the data in response to a NERC Rules of Procedure Section 1600 data request. This requirement is purely administrative.
Group
FirstEnergy
Doug Hohlbaugh
Yes
FirstEnergy (FE) recommends that the new TPL standard (TPL-001-2; now TPL-001-4) be reflected under the related standards section of the SAR. The drafting team should consider the need/benefit of having the proposed MOD-032-1 standard include modeling requirements listed in Requirement R1 of the new TPL standard. It's FE's understanding that the new TPL standard envisioned having the modeling requirements reflected in Requirement R1 removed from the TPL standard when the MOD standards were updated. At a minimum, references to existing MOD standards will require revision in the TPL standard if R1 in the TPL standard is retained.
Yes
See response to Question 3
Fundamentally, FE supports the approach taken in the proposed MOD-032-1 to remove the "fill-in-the-blank" aspect of the standards and to remove the Regional Entity as being integral to the modeling building effort. However, FE has some concerns in the details as proposed in this draft. The following outlines our primary concerns. Additionally, our comments raise questions that we would like addressed by the drafting team. Requirement 1 – As written, this requirement may provide too much flexibility for the Planning Coordinator (PC) to specify "the level of detail to which equipment shall be modeled" (R1, Part 1.4). For instance what if one PC requires a bus/branch model while another prefers more detail and obligates a node/breaker model? While drafting teams must strike an appropriate balance in describing "what" is required and avoid specifics on "how" to accomplish an industry obligation, sometime more detail may be appropriate to drive consistency; particularly in a given Interconnection. The Rationale box for R1 which states that "It would likely be most efficient for PCs to fashion their data requirements and reporting procedures with the interconnection-wide common format in mind" supports our concern. More on R1, Part 1.4: It is our interpretation that the level of detail and model requirements, including system topology, handling of conductor changes along a transmission line, etc may be different each model type. For instance, the details of a steady-state model may differ compared to a short-circuit model. Is FE's understanding correct? R1, Part 1.2 – It is important that the specified data format established by a PC be publically available and not unique to any particular vendor software application. Requirement 2 - The PC should be required to provide any BA, GO, LSE, etc, their initial data requirements and thereafter whenever any change is made. The need for a PC to retain compliance evidence that it provided its requirements within 30 days upon request is an unnecessary administrative compliance burden that does not support reliability. In reality, a PC will likely make available its requirements through a website, but they should still be required to communicate changes to affected parties. Requirement 5 - Requires that PCs submit data to the ERO (or designee) for interconnection-wide models. As stated above, FE is concerned about the diversity of data formats, details, etc that PCs will establish. The existing MOD standards have the Regional Entities (or RROs) drive the model requirements so the opportunity for

differences is much lower that what may occur in the proposed standard. In the Eastern Interconnect, there are 51 PCs within 6 regions. This may create widely varying model data requirements and reporting procedures. We suggest that within the Eastern Interconnect the ERAG, rather than the PC, be designated to drive consistent model building requirements and practices to develop power flows, short circuit and dynamic base case models. The standard then would assess functional entities adherence to the established ERAG practices.
No
See response to Question 5
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.
Group
Bonneville Power Administration
Jamison Dye
Yes
BPA has concerns with the requirement to provide short circuit data (zero-sequence information) in powerflow base cases. Currently this data is not part of the submittal required by WECC in the basecase model representation...nor is it required to be included by the WECC DPM (data preparation manual). The protection groups obtain this information from Aspen One-Liner (the data exists and is maintained in a separate database). This new requirement creates a redundancy and increased workload without increased reliability. BPA recommends that the drafting team consider addressing this disparity.
BPA believes that the requirement to include short-circuit data demonstrates that different databases are being used to accomplish the planning and operation/protection of the power system and that the detail of the models are specific to address the underlying need. For example, wind models at the planning level are equivalent to a single generator, step-up transformer, collector system, and the interconnection transformation to the BES (bulk electric system) while the individual turbine units are modeled with all of their intricacies for protection purposes.
No
BPA has concerns about validating operational models with planning models, specifically in ensuring the alignment between state-estimator models and planning representations of the power system. BPA believes that there are significantly different degrees of modeling detail required by each and a history of the needs/purposes for the two models not being the same. BPA recommends the drafting team consider addressing this concern.
BPA believes that the alignment between the state-estimator and planning representations of the power system is challenging. The detailed representation of a breaker/node model vs. the bus/branch approach utilized by most powerflow programs have presented obstacles that ended up in a stalemate between operations and planning. For example, a substation with a ring bus topology can contain significantly more data points than the single bus number it is assigned in a powerflow model. BPA recommends that the drafting team remove the requirement to align state estimator and planning representations to eliminate this challenge.
Group
Western Area Power Administration
Lloyd A. Linke
Yes
No
The proposed MOD-032 replaces MOD-010 through MOD-015. In the fill in the blank standards, MOD-014 and MOD-015, the RRO had the responsibility to build the interconnection specific models. The

proposed MOD-032 standard states that each PC must submit the data to the ERO or its designee to support the creation of the interconnection specific models. There is some concern that this inclusion of the PC in the data collection process and the elimination of the RRO in building the interconnection model may create issues in building the interconnection specific models. In the Eastern Interconnection, it would go from 6 RRO regions gathering and coordinating regional data to raw data sets from the 51 individual PCs possibly. ERAG in the EI has discussed this and believes a solution can be developed but acknowledges a change in the existing process needs to be made. Some uncertainty to what this new process looks like. Also, it may be that the PC has not been involved with the model development or data collection which means that some PCs may not have the infrastructure to even collect data.
No
The proposed MOD-033 drafts a new validation process that requires the PC to validate the data collected in the MOD-032 process for both steady state and dynamic analyses against actual system responses. Data/conditions collected for a planning horizon must be validate against actual system behavior represented by a state estimator case or other Real-time data sources. Typically planning models are built for non-coincident peak time frames for a worst case scenario in the planning horizon which makes it difficult to validate against a real-time event. Also, a PC is an entity not typically involved in real time processes. They would be requesting data from an RC or TOP in an operating horizon and benchmarking a model they did not create against the data received from a real time entity. I would also assume they would have to validate which model is providing valid information or results. It seems a difficult task to bench mark these two model sets especially when the PC has only the responsibility to collect the data and no obligation to build models in the planning horizon and does not typically have access or functional responsibility in the development of the real time system data. I believe there could also be confidentiality concerns for a RC and TOP with being directed to provide any PC actual system behavior data.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
Yes
We agree with consolidation and simplification.
MOD-032-1 does not apply well to the way that WECC is structured. Planning Coordinators vary widely in size and scope across the WECC footprint. (Also, some entities within WECC are not registered as PCs, and yet are not under the jurisdiction of another PC.) Making PCs responsible for the development of modeling data requirements for each of their respective areas invites the possibility of issues with data compatibility across the interconnection, and is inefficient and duplicates effort. A WECC variance would probably need to be written into the standard to preserve the existing process that relies on a WECC Data Preparation Manual to define the technical model data requirements and reporting procedures for the interconnection. Need more detailed explanation of expectations for validation accuracy. How many and which models need to be validated as a part of the documented process?
No
Need more detailed explanation of expectations for validation accuracy. How many and which models need to be validated as a part of the documented process?
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2010-03 Modeling Data (MOD B) Standard Drafting Team

October 7, 2013

RELIABILITY | ACCOUNTABILITY

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Introduction

The 2010-03 Modeling Data Standard Drafting Team (SDT) thanks all participants for their feedback in finding ways to improve the proposed MOD-032-1 and MOD-033-1 Reliability Standards (MOD B standards). In response to the first formal posting of the standards, the SDT received input that was focused on several issues that assisted the SDT in refining the standards to the set of standards now posted for comment and ballot. The SDT carefully considered all comments in determining whether to make particular changes to the standards, and this document is intended to provide a summary explanation of the SDT's deliberations.

The standards were posted for a 45-day public comment period from August 26, 2013, through September 4, 2013. NERC asked Stakeholders to provide feedback on the standard and associated documents through a special electronic comment form. There were 72 sets of comments, including comments from approximately 201 different people from approximately 91 companies representing all 10 Industry Segments.

Furthermore, the SDT thanks the industry for their continued support and collaboration in discussing the improvements to the existing MOD-010 through MOD-015 standards. The drafts now posted reflect significant discussion and consideration of different viewpoints, and they also reflect an approach to fulfill the industry's obligation to respond to remaining regulatory directives related to MOD-010 through MOD-015.

During the posting of the first draft of the proposed MOD-32-1 and MOD-033-1 Reliability Standards, the drafting team asked questions related to the project's Standard Authorization Request (SAR) and about the approach in each of the standards. As a whole, the SDT found that the responses were thoughtful, organized, and focused.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Vice President and Director of Standards Mark Lauby at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Consideration of Comments

Process

During the initial posting for comment and ballot, some commenters disagreed with the approach to post the SAR simultaneously with the MOD B standards. The SDT appreciates these concerns, and notes that this is an issue that is being addressed with collaboration among NERC staff and the NERC Standards Committee. Specific items related to posting were discussed at the September 19, 2013, Standards Committee meeting in Denver, CO. The SDT understands that coordination is occurring with respect to the posting schedule, and it appreciates participants' understanding of this issue as we move forward to find consensus on the specific substance of the standards.

Standard Authorization Request (SAR)

Commenters also provided input into the scope of the SAR, to include suggestions for specific changes in certain places. The SDT did not make changes to the SAR, as they do not change materially the substance of the SAR's scope. The SAR provides discussion on the scope of the project, and the resulting standard is within that scope. For example, while the discussion in the SAR related to supplying data and models provides an extensive list of functions and an associated table (Table 2), it indicates that such functions should be provided data "as applicable."

Consolidation, Simplification, and Supplemental Information

Many commenters provided support for the consolidation and simplification approach in MOD B, while other commenters requested some level of separation of the short circuit items from the MOD B standards. Commenters also agreed that that the approach in MOD-032-1 generally aligns with current practices. The SDT appreciates the support for simplifying and consolidating the existing standards into a more useful set of Reliability Standards, and it also notes that the standards in many respects do not prescribe how an entity must organize or otherwise conduct its operations to meet the standards.

In addition to the consolidation and simplification, commenters thanked the SDT for providing the supplemental information alongside the formal posting of the MOD B standards. In particular commenters appreciated the coordination with NERC compliance operations, and they found the additional background information helpful. The SDT appreciates this input, and wants to continue to highlight that information going forward, particularly the consideration of issues and directives, as many approaches reflected in the standards are informed by the discussion regarding remaining directives. The SDT has also attempted to explain the directives in the rationale boxes in the standards.

A commenter suggested to combine the MOD standards with the TPL standards as part of a standards restructuring recommended by the Independent Experts Review Project report, but the SDT notes that such a combination is not in scope of what the SDT is addressing in this project, and such a transition of the standards family would be part of a larger shift outside the shift of this project. The new construct approach must be developed separately to ensure all issues related to such a restructuring are coordinated with the industry.

A comment asked for clarification on whether Transmission Owners (TOs) would still be responsible for submitting the steady state and dynamic data for Generator Owners (GOs) since MOD-032 R3 states that "Each BA, GO, LSE, RP, TO, and TSP shall provide steady-state, dynamics, and short circuit modeling data to its TP) and PC according to the data requirements ...." . The SDT response was that each data owner is responsible for the data for their equipment, but nothing in this standard, similar to other Reliability Standards, precludes agreements to provide on behalf of another entity. Such arrangements do not diminish the underlying data owners' responsibility, nor does it make the entity submitting on behalf of another subject to the underlying data owners' compliance obligations in this respect.

A comment stated that GO requirements in MOD-010, 11, 12 and 13 were well-defined and reasonable in scope. The SDT response is that the mentioned standards are not all approved and may not be consistent with outstanding directives. See also the discussions on “RRO” applicability later in this report.

Some commenters suggested changes to the structure of MOD-032-1, such as combining Attachment 1 into one column instead of 3 columns for steady-state, dynamics, and short circuit. This was not supported by the majority of entities and the SDT thought the current three columns provided more clarity. Another commenter wanted to remove all requirements in MOD-032-1 except R3 and insert a reference to Attachment 1 in R3. This suggestion was not supported by the majority of commenters or the SDT, as the standard outlines several other obligations among and between entities, and the other requirements added clarity. Requirement R2 was removed, however, and that is discussed later in this report.

Applicability

A commenter asked that “Planning Coordinator” be replaced with “Planning Authority”. The SDT notes that these are the same intended functions, and it has modified the applicability section to indicate that it applies to the “Planning Authority and Planning Coordinator.” The proposed standards combine “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to “Planning Authority and Planning Coordinator.”

A commenter also suggested that the functions be made singular to align with other standards. The SDT has made that change, but notes there is some inconsistency among the body of NERC Reliability Standards, even though it has no substantive effect on application of the standards.

Coordination with Other Standards

Several comments expressed concern there is duplication of requirements regarding MOD-032-1 with TOP-003-2 and IRO-010-1. The SDT compared the standards and has determined that the standards do not duplicate work nor compliance responsibilities. MOD-032-1 is focused on longer term planning analysis, i.e., one year, five year and beyond. Also, MOD-032-1 is applicable to the Planning Coordinators (PCs) and Resource Planners (RPs). Both functional entities are not included in the TOP or IRO standard.

With respect to TOP-003-2, the Purpose reflects real time analysis and monitoring. Therefore, the data to be provided to the Transmission Operator (TOP) by the applicable entities will not be the same as in MOD-032-1, nor will the frequency of receipt of data be the same, Specific to TOP-003-2, R1 states the data to be provided is for Operational Planning Analysis. This term, as defined in the NERC Glossary of Terms, is as follows:

> An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

By this definition, which requires data to support real time operations and planning, the SDT does not believe there is duplication with MOD-032 and its applicable data requirements.

For IRO-010-1a, the SDT concluded that there is no duplication of work or compliance responsibilities consistent with the same explanation for TOP-003-2. The data to be provided in the IRO standards supports real time analysis and Operational Planning Analysis.

There were also comments regarding duplication of MOD-033-1, R2 with the TOP and IRO standards. The SDT reviewed the standards and did not identify duplication. MOD-033-1, Requirement R2 does include possible submittal of Real-time data but it is in response to a PC's request for this data as well as other types of data.

Other commenters questioned whether MOD-032-1 has similar requirements to FAC-008, TOP-002, and VAR-002. VAR-002's similarity is in Requirement R4, where it requires the Generator Owner to submit a subset of MOD-032-1, Attachment 1 data for generator step-up transformers for the Real-Time Operations Horizon (1 hour or less). TOP-002's similarity is in Requirement R19, which requires the Balancing Authority (BA) and TO to maintain accurate computer models for analyzing and planning system operations for Operations Planning. The VAR-002 and TOP-002 standards are for the Real-time Operations and Operations Planning time horizons. The MOD-032-1 and -033-1 standards are effective for the Long-term Planning horizon, which is after the time horizons for the TOP and VAR standards. The FAC-008 standard is applicable to the Long-term planning horizon as well and covers the documentation for determination of facility ratings by the GO and TO and a provision of those ratings to the same entities as required by MOD-032-1 (PC and TP). FAC-008 also includes the RC, TO, and TOP. Submission of facility rating data for MOD-032-1 to the PC and TP could also satisfy the FAC-008 requirement to send facility rating data to PC and TP, but they serve different purposes. Short term de-ratings, MW, and MVar limitations should not be submitted for MOD-032-1 unless those de-ratings and limitations extend to the Long-term horizon.

MOD-032-1

Short Circuit Data

A few commenters questioned if steady-state, dynamics, and short circuit data should be in a separate standard and if short circuit data should even be part of any NERC standard data request. The SDT considered the comments from stakeholders, and while a few would like to separate them, the majority preference is to combine them as it creates fewer requirements. Regarding the need to include short circuit data, the directive from FERC Order No. 890, paragraph 290, specifically requires inclusion of short circuit data. Having the short circuit data as part of this standard supports that information being shareable on an interconnection basis, particularly to support analysis at the seams, and it supports TPL-001-4, Requirement R2, which requires the Transmission Planner (TP) and PC to include a short circuit analysis as part of its annual assessment.

A commenter suggested that the results of analyzing this data are already available in two places - as part of the annual FERC Form 715 filing, which provides a summary of all Transmission Planning activity for the prior calendar year, as well as in the annual Grid Assessment Study Report. In response, the data itself may not be available or available in a form that can be used from those sources.

In addition to the directive to include short circuit data, the SDT also offers the following observations. System protection is often perceived to be the sole use for short circuit data. However, short circuit data is also used in conjunction with power flow and dynamics applications, for example, to adaptively calculate unbalanced fault shunt admittance for prior outages and sequential clearing in dynamic simulations, particularly where regional stability is or could be impacted.

Regional Reliability Organizations (RRO) Applicability

Many commenters expressed concern over Regional Reliability Organizations (RROs) not controlling the data collection procedure as in the current MOD-010 through MOD-015 standards. Notably, four of those six standards were not approved by the commission as “fill-in-the-blank” standards in part because of the RRO applicability. The SDT notes that the standard does not preclude a Regional Entity's (RE) involvement in the data collection, however, the designation RRO is not in the NERC functional model, and NERC Reliability Standards' applicability is based on those functions. Therefore, NERC cannot require the “RRO” to develop data requirements and reporting procedures. The structure of the requirements in MOD-032-1, culminating in the requirement to make available data to the ERO or its designee for each Interconnection, is created specifically to support Interconnection processes, however. The standards create a framework for the continuation of the processes that have worked in each Interconnection.

Registration Concerns

A few commenters raised registration concerns. One commenter did not know who its PC was, while some PCs did not know who their data owners were. The SDT agrees with commenters that for this standard to work effectively, the PC will need to know all registered entities (TOs, GOs, TPs, Distribution Providers (DPs), Load Serving Entities (LSEs), Transmission Service Providers (TSPs), and RPs) within its purview, and vice versa (entities need to know who their PC is). The SDT notes these comments and guidance at the end of the standard addresses some of these issues. The SDT believes continued regional clarification and outreach is also necessary, and the SDT will pass this on to NERC and Regions. The guidance also provides explanations for data owners to begin working with their Transmission Planners to identify their Planning Coordinator. One commenter also stated it would be helpful if NERC or the Regional Entity would provide such a mapping (listing of registered entities (TO, GO, TP, DP, LSE, TSP, RP) within their purview) to the PCs on an ongoing basis so that PCs and data submitting entities can stay current on their obligations. The SDT will pass this onto NERC also.

Facilities

A commenter suggested the drafting team should provide guidance on how the PC should handle Generating Units with capacity limits below the NERC functional entity registration limits. The commenter indicated that generators below the 20 MVA single unit and 75 MVA plant are still desired to be modeled both in the Interconnection-wide case and PC-level models. A different commenter expressed the opposite concern. In response, the SDT notes that standards apply to functional entities and NERC's jurisdiction relates to the Bulk Power System. While such data is not precluded to be modeled, it is outside the scope of the reliability standard itself. Such data is typically provided through other existing procedures or arrangements. Furthermore, in Attachment 1, the SDT has also clarified the specific Demand data required by Attachment 1 is the Demand aggregated under each bus identified by the TO.

Requirement R1

Many commenters raised concern with the PC-developed data collection procedures. Specific concerns were data collection consistency and whether a PC could require data that is not needed for reliability. Commenters are concerned PCs will ask for items not needed and PCs will have inconsistent procedures. The SDT discussed this issue in length and added clarification to Requirement R1 that PCs must create their data requirements and reporting procedures jointly with TPs, and the requirement is more specifically linked to support Interconnection-wide modeling to address inconsistency concerns. In addition, the SDT notes that the data in attachment 1 is separate from the other criteria and no longer "at a minimum."

A few commenters questioned Requirement R1, parts 1.1 through 1.6, asking why this criteria was included in the requirement and not in an attachment. The SDT notes that attachment 1 is part of Requirement 1, and that it specifies the data that must be provided. The rest of the criteria inform details that must be included in the data requirements and reporting procedures relative to that data.

A few commenters stated that GO requirements in MOD-010, 11, 12 and 13 are presently well-defined and reasonable in scope. MOD-032-1 proposes to leave the type of model, level of detail, size cutoffs (if any), case types and scenarios to be established as part of the data requirements and reporting procedures.

One commenter raised questions about Requirement R1, Part 1.4, concerning the level of detail and model requirements, including system topology, handling of conductor changes along a transmission line, etc., and that it may be different for each model type, such as the details of a steady-state model may differ compared to a short circuit model. The SDT confirms this understanding and notes that this is why the requirement is written this way; it is expected that the level of detail may vary with model type.

A Commenter asks that data format established by a PC be publically available and not unique to any particular vendor software application. The SDT notes that the standard does not require publicly available software, but it also does not require or prohibit a particular vendor software application. The PC and TP jointly create the data requirements, which may mean specification of a particular software application.

A commenter also asked whether NERC is planning to work with vendors on data interchange among software platforms, and the SDT notes NERC coordination of this type is outside the scope of the drafting team. However, the SDT is encouraged by focus from NERC, various modeling working groups, and the Planning Committee in various areas related to modeling.

Some text changes were suggested such as insertion of the following parenthetical at the end of MOD-032-1 R1.5 "Specification of the case types or scenarios to be modeled (for steady state and dynamic data sets)" to limit the case types or scenarios to steady state and dynamic. Since some entities also create short circuit case types, this language was not added.

A commenter suggested that use of the term "case type" is confusing, as these are already specified as steady state, short circuit, and dynamics. Part 1.5 also states that the scenarios to be modeled should be included. The commenter suggests there is no need to specify those scenarios as part of data collection. The SDT disagrees and has retained that language, because "case type" and "scenarios" terminology is clear once attributes are assigned to the model sets by respective PCs (e.g. years, seasons, forecasts, transactions, peak, off-peak, etc.).
There were comments on the provision to provide the data at least once every 13 calendar months, and whether it should be modified or have language added concerning alternative schedules. The SDT notes that "at least 13 calendar months" is meant to indicate a timeframe that is generally repeated at the same time each year, but considers that an exact 365 day timeframe between submissions may not be practical for a number of reasons, including holidays, weekends, or even operating emergencies. For example, if an activity is conducted on July 1 of each year, but on year 2, July 1 is a Saturday, conducting such activity on July 3, the first Monday, would still be within 13 calendar months of the previous iteration of that activity.

Requirement R2

Requirement R2 from the last posting has been eliminated. Instead, Requirement R1 now includes a new part requiring the PC and TPs to include specifications for distribution of the data requirements and reporting procedures. For purposes of this report, references to Requirements R1 through R5 of MOD-032-1 relate to the previously posted version (i.e., because of the removal of Requirement R2 since the last posting, Requirements R3 through R5 were renumbered, and subsequent discussion in this report of Requirement R3, R4, and R5 are in context to the previously-posted version, and they map to newly renumbered Requirements R2, R3, and R4, respectively, in the currently-posted draft MOD-032-1).

A few commenters suggested distribution to data owners upon any modification instead of providing to data owners upon request. Others raised the concern that R2 is administrative and should be eliminated, and that the PC should simply deliver the data requirements and reporting procedures to the data owners once they have been developed. The SDT discussed that the requirement clarifies the responsibility and obligation of the PC to distribute the procedures upon request and is therefore not purely administrative.

Commenters suggested MOD-032-1 Requirement R2 falls under the Paragraph 81 criteria. The Paragraph 81 criteria addresses "requirements that obligate responsible entities to report to a Regional Entity, NERC, or another party or entity "on activities *which have no discernible impact on promoting the reliable operation of the BES* and if the entity failed to meet this requirement there would be little reliability impact." (Emphasis added).

The SDT does not agree that Paragraph 81 is invoked since the submission of data for use in the planning models does constitute "promoting the reliable operation of the BES" and that there would be a "reliability impact" if data is not submitted for the planning models since planning the transmission system for future growth is necessary to ensure reliability.

In response to comments and questions on Requirement R2, however, the SDT discussed that the PC has an interest in ensuring that it receives data to support the PC's obligations. Furthermore, the details of Requirement R2 could have resulted in unintended over-breadth. In response, the SDT has decided to include within R1 a part (Part 1.3) requiring specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing data. In this manner, the SDT believes it addresses the general issue of availability while simultaneously leaving decisions regarding distribution or posting to the determination of the jointly developed data requirements and reporting procedures.

A commenter asked the SDT to consider modifying Requirement R2 to require the PC to be responsive similar in concept to what is required in FAC-010-2.1. Requirement R5 of FAC-010-2.1 states: "If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why." The SDT did not make this change. Requirement R2 was included to support an entity being able to acquire established requirements and procedures, and it was not intended to be a forum for making changes to those requirements and procedures.

Requirement R3

A couple comments questioned why the TP and PC are listed to receive data. The SDT notes that while the PC and TP are listed, it also states "according to the data requirements and reporting procedures developed by its Planning Coordinator in Requirement R1," so this could be further specified in the procedure defined in Requirement R1.

One commenter suggested the sentence, "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient" is not needed since it is not a requirement. The commenter suggests it is a measure of compliance already adequately captured in the Measure. In response, the SDT notes that it provides additional emphasis and clarity to the requirement that the full submission of data is not required if it has not changed. This was also a key consensus point.

Requirement R4

Several commenters raised concerns regarding the Requirement R4 feedback loop. Some questioned if it was necessary while others thought it did not go far enough. Additionally, a comment asked whether the PC or TP will be required to use erroneous data if they cannot continue the feedback loop to their satisfaction. Also, several commented that 30 days is too short to provide the feedback.

The SDT discussed these comments and Requirement R4 at length, which included discussion regarding whether to remove the requirement. The discussion to remove it was in light of changes to Requirement R1, especially since changes to Requirement R1 focus on the PC jointly developing reporting procedures with the TP, and reporting procedures could reasonably be expected to cover issues of submission acceptability, usability, etc. After much discussion, however, the SDT decided to keep requirement R4 and made modifications in response to comments. The SDT made the following modifications:

1. Requirement R4, Part 4.2 (related to user-defined models) was removed, though the concept was added to attachment 1 under the dynamics data heading (also see the more extensive discussion on confidentiality concerns, below, as this is related);

2. old Part 4.3 (now Part 3.2) was changed from 30 days to 90 days; and
3. Requirement R5 (now Requirement R4) was modified to state that the PC submits models "reflecting" the data it receives to support creation of Interconnection-wide cases to address the concern about whether the PC is obligated to use data it knows may be inaccurate (i.e., the PC can modify the data upon submission to reflect a more accurate representation if necessary).

One commenter raised concern that M4 was too prescriptive. After review and discussion, the SDT disagrees, as M4 provides numerous ways to meet Requirement R4.

Requirement R5

Commenters expressed concerns about the Interconnection-wide case building process and Requirement R5. Some Commenters suggested using section 1600 data request to collect data for interconnection model building. Regarding section 1600, the SDT points out that this standard is about specifying the relationship of obligations between and among different functional entities, not about providing data to the ERO.

Many Commenters expressed concerns that even though the PC can create Planning Horizon models for its region, they cannot build a 'standalone' model to perform studies without the coordinated efforts of external entities within the planning horizon (i.e. Interconnection models). Similarly, some comments asked who is responsible for building the Interconnection-wide cases under the standard. The SDT points out that while the standard does not prescribe how the Interconnection-wide case is built, the standard is limited to directing the PC to provide the information to the entity that does create the model (the standard is not a standard to create the Interconnection-wide case, it is a standard outlining obligations among other functions to support collection of data for use in the Interconnection-wide case). The ERO has an interest in ensuring the interconnection-wide cases are built, and that interest exists without the need for a standard directing their compilation. This is also why both Requirement R1s from MOD-014 and MOD-015 are not being mapped to the new proposed standard.

Similarly, a commenter suggested that the drafting team should consider developing a separate standard for each Interconnection (referencing IRO-006 as an example) in recognition of the current modeling practices employed in each Interconnection. The SDT agrees that the standard should account for different practices among Interconnections. Similar to the explanation above, one of key reasons for structuring MOD-032-1 in the way it is structured is to provide a framework that supports and recognizes the differences among Interconnections in modeling practices, and a separate standard for each Interconnection is not necessary to support that framework.

Another comment concerned making sure that the "fill in the blank" aspects of MOD-011, MOD-013, MOD-014, and MOD-015 are not repeated. In MOD-032-1, this was fixed by requiring the PC to make available the models reflecting its planning area to the "ERO or its designee. The reliability-related task that Requirement R5 addresses is the obligation of the PC to make available their data in support of the Interconnection-wide case. The SDT also notes that the standard does not preclude RE involvement (and, as discussed earlier, the term RRO is not in the NERC functional model).

Commenters also raised concern that PCs need to collaborate to build Interconnection-wide cases. The SDT agrees and notes that the framework does not prohibit such collaboration.

Several commenters raised concern that Requirement R5 required each PC to submit data to the ERO or its designee to support creation of the Interconnection-wide cases, and that the PCs have no obligation to collect data on the same schedule and no obligation to build the same set of models. The SDT clarified that Requirement R1 procedures support Interconnection-wide case building, and the PC obligation under Requirement R5 (now Requirement R4) would inform development of the data requirements and reporting procedures.

A few commenters raised concerns regarding Requirement R5.2 related to data modification. Specifically, the concern was whether the act of a PC modifying data would cause a noncompliance for making unreported modifications to support the Interconnection-wide case, or whether all modifications of any type would need documentation. The SDT agrees and has removed R5.2 and clarified that the PC is submitting models for its area that reflect the data it receives from its data owners.

MOD-032-1, Attachment 1

Attachment 1 – Specific Change Requests

Many commenters submitted concerns over the level of detail in Attachment 1. Some of the more frequently noted concerns shared by a large number of commenters were:

- it was too prescriptive;
- it required information that was not needed for reliability;
- it was too onerous for a "at-a-minimum" requirement; and
- it allowed for the PC or TP to potentially impose additional reporting requirements

The SDT agrees with the comment that Attachment 1 was too prescriptive. In response, many of the details and the prescriptive nature of the data items have been removed from Attachment 1. The number of data items requested has also been limited to those needed for reliability purposes. Additionally, language that was vague has been improved. It is intended that individual PCs and TPs will address the appropriate amount of additional detail necessary through their individual procedures and data submission requirements as agreed upon through a stakeholder process. The applicability of functional entities was reviewed. The standard does not preclude entities collaborating to ensure appropriate data submission – for example LSEs can work with the TOs to ensure that the demand information submitted is appropriate. The SDT directs commenters to the revised Attachment 1 included in the draft MOD-032-1 standard.

In response to some of the specific comments, the SDT provides the following additional clarification:

- Auxiliary load being netted with generation can be problematic, since the auxiliary load is necessary during dynamic studies to model plant outputs at their maximum value. Additionally, Attachment 1 has been updated to clarify that auxiliary load data shall be provided for normal plant configuration.
- Regarding concerns for item # 9 (under steady-state data), the SDT recognizes the need for the PC/TP procedures to have flexibility in configuring its procedures to potentially account for modeling data for newer generation and transmission technologies. The PC/TP procedures shall include the level of detail that should be provided to support the interconnection-wide models. These procedures are expected to be developed through individual PC/TP processes after thorough vetting of specifications and stakeholder consensus. Given the other requirements in the standard (Requirement R5, now Requirement R4) it is expected that all the PC/TP procedures would conform to how the ERO (or its designee) drafts their procedures – thereby lending consistency across the various PC/TPs.
- Regarding the concern of providing data for MOD-026-1 and MOD-027-1, and perhaps double compliance jeopardy, the SDT notes that although there may be some overlap in that data, the purposes of the standards are different. MOD-032-1 is a data <u>submission</u> standard; other standards referenced are largely data <u>verification</u> standards.

Short circuit Data

Various comments were received pertaining to the inclusion of short circuit data in the MOD-032-1 standard. A summary of those comments and corresponding responses by the SDT are included below.

- Standards pertaining to development of Interconnection-wide cases such as MOD-032-1 should not include short circuit data.

  - The SDT agrees that developing interconnection-wide short circuit models may have limited value – and notes that that is not the intent here. The new TPL-001-4 standard (pending approval) does require that short circuit analyses be performed by the PC and TP. Short circuit data is being collected with the intent of better coordination of this data and short circuit analysis along the PC/TP seams. Additionally, the FERC directives also require inclusion of short circuit data in the standards.
- If short circuit data collection is included, its submission should only be required, at a maximum, once every 13 calendar months.
  - The SDT agrees with the 13-month data submission requirement.
- Additional detail requested in Attachment 1 indicating how the data submission requirement may be met (for example, adding language noting that positive sequence data may be substituted for negative sequence data where appropriate).
  - The SDT agrees with the intent of the comment. The PC/TP procedures should provide this level of guidance on what constitutes appropriate data substitution. The standard as written does not preclude submission of such data.
- Concern regarding potentially insufficient coordination between functional entities
  - The standard does not preclude coordination among functional entities as needed. The SDT notes that this coordination, including specifics on how the individual transmission elements will be modeled, could be part of the PC/TP process and should be adequately covered by the individual PC/TP procedures.
- Concerns for vagueness of the "Short circuit" column in Attachment 1 were expressed.
  - The SDT modified the requirements in the column by removing the details and leaving the specifics of the details for inclusion into the PC/TP procedures with stakeholder input and concurrence.

For a review of the changes made, the SDT directs the commenters to the revised Attachment 1 of the MOD-032-1 standard.

Dynamics Models

Comments were received pertaining to the requirement for submitting dynamics data as part of the MOD-032-1 standard. A summary of those comments and corresponding responses by the SDT are included below.

- In general, the standard should allow submitting estimated or typical/generic dynamic data. For newer generating facilities the standard should require submission of only unit-specific data.
  - The SDT would like to note that the standard as written does allow submission of estimated/typical data – and at the same time does not preclude submission of unit-specific data. More detailed stipulations can be included in the specific PC/TP procedures as necessary.

- Concerns with violating confidentiality agreements due to use of proprietary models; commenter recommendation that the standard should prohibit use of proprietary/user-defined ("black-box") models
  - The SDT recognizes the occasional need to rely on "black-box" models (say for newer technologies that have not yet been more universally included in commercial software program model libraries). The SDT therefore notes that use of "black-box" models shall be permitted by the standard. The revised standard, while not prohibiting their use, clarifies information required for "black-box"/user-written models in Attachment 1. Additionally, to address the confidentiality concerns, the SDT also notes that the use of proprietary models is not a requirement. To assess the reliability of the transmission system, use of generic or library models is acceptable. Should there be a need to use proprietary ("black box") models, those will

need to be supplemented with proper documentation, as noted in the revised Attachment 1. See also the more extensive discussion on confidentiality concerns, below.

PC/TP Data Requirements and Reporting Procedures

Comments received pertaining to the proposed PC/TP procedures and the SDT responses are noted below:

- Planning Coordinators should:
  (1) identify those items in their data specifications that correspond to Attachment 1; and
  (2) provide the latest data they have on hand when the data template is issued.

  - The SDT did consider the comments. There were not any other comments in support of these changes. (1) The SDT notes that the PC/TP, through their individual stakeholder process, should draft the data submission procedures such that data items in Attachment 1 are identified with sufficient clarity. (2) The latest data that the PCs have should generally be available in the models developed by the PC/TP, which should be accessible to data owners pursuant to appropriate non-disclosure agreements.

- Concern regarding impacts to data owners related to the discretion afforded to PC/TPs in drafting their procedures
  - As discussed earlier, the SDT believes the procedures developed should be jointly developed. As such, the language in R1 now reads that the procedures shall be jointly developed between the PC and each of its TPs. Additionally, the "at-a-minimum" language has been removed from Attachment 1, so that the PC/TP procedures will be vetted through stakeholders, and specifications will be put into the procedures after stakeholder consensus.

Miscellaneous

Various comments of a general nature requesting specific changes to Attachment 1 of the MOD-032-1 standard were received. Those comments and the SDT responses are noted below:

- MOD-032-1 draft standard does not seem to include Attachment 1
  - The SDT notes that Attachment 1 is located at the end of the proposed MOD-032-1 standard following the "Table of Compliance Elements"

- Comment requesting addition of item 9 under "steady state" to dynamics and short circuit columns as well
  - The SDT agrees with the comments and has modified Attachment 1 accordingly.

- Comment requesting clarification on Attachment 1 functional obligations and recourses available if data isnot available
  - In response to concerns about functional obligations, the functional obligations of Attachment 1 are clearly delineated and the function expected to provide each type of data is listed parenthetically following each data type (and that is further explained in the supporting footnote to the attachment).
  - Additionally, if the data is not available, the PC/TP procedures could include language where the data owner will need to assist the PC/TP in getting the best value through testing or estimating, and if its older equipment, it is likely already represented in the model.

Black Box Models and Confidentiality Concerns

Many commenters discussed confidentiality or non-disclosure agreements relative to user-written models. The concern is well-taken by the SDT, and the comments were very helpful.

Several commenters expressed concerns over black box models and confidentiality concerns. A few thought they should be prohibited by the standard. Others thought it would cause a data owner to either violate a confidentiality agreement or not comply with standard. The SDT made changes to Requirement R4 and attachment 1 to clarify and address this concern. The SDT also would like to clarify that the standard neither prohibits nor requires a black box or user-defined model be submitted. The standard allows use of a generic or library model as long as it provides an accurate representation of equipment.

Additionally a commenter suggested adding “where confidentiality agreements allow” to the shareability criteria. Again, the SDT notes there is no requirement to submit proprietary or confidential information, and if agreements do not allow sharing the proprietary model, the expectation is for the data owner to submit a generic or library case that is shareable.

The standard *does not require use of proprietary or user-written models*, and the changes clarify that notion even further by linking the additional information relative to user-written models to those cases where such models are provided *in place of a generic or library model*. The qualification on user-written models applies only when they are provided by the data owner; it does not require their use. Therefore, if a confidentiality or non-disclosure agreement applied to a specific user-written model prohibiting the release of that additional information, the standard would not require its use in contravention to that agreement. But the data submitted by the data owner needs to be shareable, and representation by a generic or library model would meet that criterion. The standards help support the Interconnection-wide case building process, and when model structures with proprietary or confidential information are submitted without additional information, it impedes the free flow of information necessary for Interconnection-wide power system analysis and model validation.

To facilitate the use of generic models, and to address concerns in building the interconnection-wide cases related to user-written models, the SDT would like to highlight that the NERC Planning Committee has also been discussing this issue. At the September 18, 2013, Planning Committee meeting in Denver, CO, the Planning Committee reviewed and approved, in concept, the Modeling Working Group (MWG) *Proposal for Use of Standardized Component Models in Powerflow and Dynamics Cases.* In conjunction with the standards development of MOD-032-1, this development by the MWG supports efforts so that standardized models will be capable of representing all operating or planned equipment attached to the power system with reasonable accuracy.

The following are key excerpts from that paper (The full report is available as part of the NERC Planning Committee’s September 17-18, 2013 agenda package [beginning page 15 of that .pdf document] here: http://www.nerc.com/comm/PC/Agenda%20Highlights%20and%20Minutes%202013/Draft%20PC%20Meeting%20Agenda%20September%2017-18,%202013%20--%20Denver%20Colorado.pdf):

> **Means for Developing Standardized Models**
> The industry should achieve a consensus on a set of standardized models for both powerflow and dynamics. Simulation software user’s group meetings, which are program-specific, have not been effective and are not suitable for this purpose. MWG supports industry activities to develop, validate, and maintain a library of standardized component models with a standardized set of parameters for both powerflow and dynamics. Participation from manufacturers, software vendors, and stakeholders is necessary to accomplish this goal. Modeling focus groups in each region or interconnection need to be represented in the MWG.
>
> The MWG is an industry-wide forum for developing agreement on new component models and their characteristics for representation of new technologies. The group also reviews existing standardized models for operating and planned equipment to meet the evolving needs of the industry.

The MWG incorporates modeling developments from each of the regions and interconnections. Existing regional model development and validation working groups will continue their present work. Some regions already have a set of standardized component models for use in their interconnection-wide models. Any model in a regional standardized model set should be included as part of the library of standardized models created by the MWG. Consolidation of similar user-defined models should be undertaken prior to standardization. Regions may use a subset of the industry approved standardized models. Although some models may have the same name amongst different regions, interconnections, and software programs, there exists a difference in functional details. The MWG will augment these regional efforts and strive, where possible, to consolidate the overlapping models.

Proprietary and User-Defined Models

The goal of the MWG is to have standardized, validated powerflow and dynamics component models for all equipment that can be freely shared and used for interconnection-wide studies. It is imperative that such models exist and be used to accurately analyze the interaction of devices and control systems across the interconnection to ensure reliable performance of the system.

However, when a new or novel piece of equipment is proposed for connection to the system, there may not be a standardized component model available that can accurately predict the equipment performance. Currently, some manufacturers are only providing the connecting Transmission Owner proprietary models whose details are contractually restricted from sharing, resulting in interconnection-wide models with “black box” models for some components. While such proprietary component models may be adequate for local analysis, they are not acceptable for interconnection-wide studies because they do not provide the information to engineers to accurately analyze the interaction of devices and control system across the interconnection. As such, the performance of the interconnection cannot be accurately predicted or ensured.

It is incumbent on the equipment owner to provide accurate, shareable models from the manufacturer that includes the necessary information for accurate interconnection-wide powerflow and dynamics analysis. Black box models or user-defined models without complete details that are currently in use should be replaced no later than the end of 2014 with standardized models or user-defined models that include all of the essential information. Connection agreements for new equipment should require standardized component models or shareable user-defined models that include complete details. For new equipment, exceptions to such a requirement should be mitigated by replacement of the interim models with standardized component models or shareable user-defined models that include complete details no later than six months after installation of the equipment.

All user-defined models must be able to be freely shared across the interconnection and include all of the information essential for accurate powerflow and dynamics analysis. For powerflow analysis, a user-defined model must specify all of the equations describing its characteristics and logic along with any other descriptive information. For dynamics analysis, a user-defined model must specify, at a minimum, a block diagram, equations describing the characteristics of the model, values and names for all model parameters, and a list of all state variables.

User-defined models should be placed on a swift path to inclusion in the library of standardized models. However, these models must be thoroughly reviewed, vetted, and validated by the industry as a whole before they can become standardized models. Once a corresponding standardized model is developed and validated, the regions should shift to the standardized model. The NERC MWG should serve as the central venue for those activities for North America.

MOD-033-1

Comments about MOD-033-1 asked several questions, such as what would constitute acceptable validation, how will the auditor interpret an entity's validation, and what does validation actually mean. The SDT wants to make sure that MOD-033-1 is focused on validation of "planning models." The planning model should be modified to be as consistent as possible with a real-time snap shot of topology, load, and generation pattern. While this is a difficult task, and various levels of consistency can be achieved with a reasonable amount of work, the SDT wishes to clarify that a comparison of performance is what is intended. The PC will determine a set of guidelines to determine the acceptable level of differences and methods to resolve those differences. The SDT made changes to MOD-033-1 to further clarify that the focus is on planning models in the purpose of the standard and in Requirement R1 by specifying it is the "planning" models.

Several comments questioned the validation timelines in MOD-033-1, stressing that 24 months was too frequent an interval to simulate a "local dynamic event". Some commenters indicated that the set-up of the simulation itself and completion of the simulation could take up to 18 months and the timelines in MOD-033-1 would result in a continuous amount of additional work necessitating additional staff. The SDT kept the 24 month requirement but removed the requirement to complete the simulation within 12 months of an event if an event had not occurred within the last 24 months. The SDT clarifies that the "local dynamic event" does not have to be a severe event requiring a large amount of set-up, but could be much smaller events that if done frequently over time would validate portions of the model in each 24 month period. The SDT also provided greater explanation of "dynamic local event" in the background section of the standard. In response to concern that validation every two years will be a large engineering effort, the SDT notes that the requirements are focused on planning area validation, and it leaves a lot of decisions regarding validation to the discretion of the PC.

Commenters asked for clarification of what constitutes a "dynamic local event." The SDT stated that the determination of "dynamic local event" is expected to be part of the validation process implemented by the PC. In the rationale for Requirement R1 in MOD-033-1, the "simulation of significant system disturbances and comparing the simulation results with the actual event results" is specified, but the rationale further states that "the details of 'how'" is not specified and is "best left to guidance rather than standard requirements." The Application Guidelines further state that dynamics model validation is limited to the PC area and the emphasis is on local events or phenomena, not the entire Interconnection, and the SDT has added more explanation to the background of MOD-033-1 about a dynamic local event.

Commenters expressed concerns regarding the expectations for accuracy in MOD-033-1. The SDT modified Requirement R1 to state that the PC will implement a process to conduct the model validation that includes guidelines to determine unacceptable differences and guidelines to resolve those differences.

Many commenters were concerned about which models to use in the validation. They stated that the RC Operations model should be used instead of the Near-Term planning cases that represented conditions one to five years into the future. The SDT emphasized that the planning cases should be used because the very point of MOD-033-1 is to make sure the planning cases, modified to represent a real-time condition, exhibit the same or similar performance as the operations models.

Another issue concerned validation of the data itself when a PC questions the data submitted by an equipment owner in MOD-032-1. The PC could use MOD-032-1, Requirement R4 to identify concerns with data, and the 30 day requirement for equipment owners to respond to PC in that requirement was increased to 90 days, as discussed earlier. Specifications to have guidelines to address data concerns were added in MOD-033-1, Requirement R1.4 to be included as elements in the data validation process the PC implements.

One commenter asserted that there is no technical basis for the requirements in the validation standard. The SDT has provided significant guidelines and technical basis following the requirements, and it has modified them to be more descriptive in certain cases. In addition, the rationale sections of the requirements explain the remaining directives from FERC Order No. 693 (which itself provides significant technical discussion) and additional technical reasoning.

A commenter expressed that the idea that Planning Models can be adjusted to exactly match recorded system response is false. If one is successful in identifying aspects of the Planning Model that led to divergence from observed BES response, it may be possible to improve the match. An exact match is beyond the realm of possibility. Compliance metrics for validation are therefore not suitable. The SDT agrees, and notes that "match" in the context of the validation standard is determined by the PC's judgment, not that it has to be an exact match. The determination for how close the match should be is left to the judgment of the PC and should be included in the PC's procedures for validation. Apparently replicating characteristic behavior for local events is the best that can be expected with current day technology within the scope of a PC. Interregional stability may need to be addressed at a higher level, but that is outside the scope of this standard.

One commenter stated that differences between recorded system response and dynamic model response are difficult to associate with a specific model due to the manner in which generators affect each other throughout the Interconnection. The SDT realizes that determining which model is causing a discrepancy between simulations and recorded disturbances can be challenging. However, the standard only requires comparisons for local events. Models throughout the Interconnection will not affect the local response. If the disturbance under consideration involves generators outside the local area, then it would not be an event that should be studied for the purposes of this standard.

Two commenters were concerned that Requirement R1.1 requires the use of a State Estimator. In response, the standard does not require that a state estimator be used. The requirement is to compare a planning power flow model with actual system behavior which could include real time data sources rather than a state estimator.

One commenter questioned if the Application Guidelines section of the Standard is "primary law" or is suggestive guidance. This section is guidance. Any mandatory items are contained in the requirements.

One commenter suggested that the drafting team consider other alternatives to approaching the FERC directive instead of developing a validation standard. The SDT believes that the standard that has been drafted is the best way to respond to the directives, and no alternative approaches with justification about how they satisfy the directives have been articulated through input or outreach.

A commenter raised concern regarding whether the measure and requirement were mislabeled. The SDT confirmed that the requirement and measures were labeled correctly.

One commenter questioned the rationale for 30 days in Requirement R2 as an appropriate timeline for providing data. The SDT believes that the data required by Requirement R2 is readily available and that 30 days is an appropriate time frame.

One commenter stated that Requirement R1 should include "each Planning Coordinator, in conjunction with each of its Transmission Planners, must . . ." The SDT did not make this change because it is appropriate for the requirement to be placed on the PC. If the PC wants to involve its TPs in developing the procedures, then the standard allows the flexibility to do so.

One commenter suggested that MOD-33-1 should be changed to include short circuit model validation. While it may be good utility practice to attempt to validate the short circuit model, the SDT does not believe this should be a requirement in the standard. This would be very burdensome to accomplish.

One commenter believes that MOD-33-1 should include a requirement to make corrections to data within 60 calendar days when unacceptable differences in performance are found. The SDT decided to leave this unspecified. It is up to the judgment of the PC when a correction is needed and when to make the correction.

One commenter suggested that in R1, “must” should be replaced with “shall” to be consistent with other standards. The SDT agrees and made the change.

A commenter asked that responsibility under Requirement R2 should be expanded to equipment owners to provide “actual system behavior data,” and the commenter proposed that R2 be worded to include them. In response, the type of data that the equipment owner may have, such as PMU or DFR data at a generator site, would generally be available at the RC or TOP, and the SDT did not add those functions to that requirement.

One commenter recommended that either MOD-032-1 or MOD-033-1 contains some language that requires each RC, TO, GO, LSE and TO to “self report” to the PC any changes in operational settings or other impactful actions within a certain period of such change. The SDT does not believe this is necessary because the data will be updated at least once every 13 months. If, in between updates, the comparisons between simulations and actual system data show a discrepancy, the PC will be contacting the data owner and any changes would be noted then.

One commenter suggested that the PC be required to perform a data check for all the data that it receives. Data checking should be done by the data owner prior to submitting the data to the PC. The PC is required to compare simulations using the data in the model to actual system measurements. The validation efforts required by MOD-033-1 is not the same as data checking.

One commenter recommended that the requirement to align state estimator and planning representations should be eliminated because of the potentially different topologies used by each (node-breaker in state estimator and bus-branch in planning cases). Another commenter was concerned that the state estimator case or other Real-time data may not contain enough level of detail required to validate the case. However, the standard does not require the two models to be aligned or to have the same level of detail. It just requires them to be compared. This can still be done even if the topologies are different. The comparisons should be made on major elements, not on every element in the case.

Some commenters suggested rewording of Requirement R1.1. The SDT has reworded Requirement R1.1 to require only the comparison of the power flow model to actual system behavior and has added a new R1.3 to indicate that the PC must establish guidelines for unacceptable comparisons.

One commenter asked for clarification on how an auditor will measure whether a PC has done enough validation to satisfy obligations in Requirement R1. The standard requires the PC to have a procedure and to make comparisons between planning models and actual system behavior data. The PC must have a procedure and follow it. The amount of validation done should not be relevant.

Some commenters offered rewording suggestions for R2, and the SDT made some changes to the requirement for clarity.

One commenter asked how the PC is going to validate data and questioned if there is an EMS case that is compatible with PSS/E. The standard requires a comparison of a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources. The state estimator case does not have to be compatible with PSS/E and it does not need to have the same level of detail. It just requires them to be compared. This can still be done even if the topologies are different. The comparisons should be made on major elements, not on every element in the case.

One commenter suggested that Transmission Operator should be added in the 6th line of M2. The SDT agrees and has added this.

One commenter suggested that the RRO or NERC, rather than each individual Planning Coordinator, should determine the how large the discrepancy between the system model and actual system performance can be. The SDT believes that this flexibility is needed for each PC because each PC's particular situation can be different (e.g. different voltage levels, different accuracy in real time data, etc.).

One commenter suggested re-wording for Part 1.2. The SDT agreed that the wording for 1.2 was not very clear and has re-worded it to say "Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response at least once every 24 calendar months through simulation of a dynamic local event. If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event."

One commenter stated that having an individual PC evaluate its own bubble would miss the impact that would be identified on large-scale system performance. However, the intent of the standard is to evaluate local models. When all PC's are doing this, then the large-scale performance benefits. Ultimately, evaluation of the large scale performance is the responsibility of the ERO, not individual PC's.

One commenter expressed a belief that there could be confidentiality concerns for an RC and TOP being directed to provide any PC actual system behavior data. The SDT does not see specific concerns with this data being provided to a PC.

One commenter stated that requirement R1.3 is redundant as it is already covered in requirements of the proposed MOD-032-1. The SDT does not see a redundancy issue, but has modified part 1.3 (now 1.4) to require the PC to have guidelines to resolve differences in performance between planning models and real time data, which might include provisions on whether and when to use the provisions of MOD-032-1.

One commenter stated that the reporting of data and modeling validation efforts is not presently part of the requirements in MOD-033-1. This is true, but the SDT does not see a need for the validation effort to be reported to anyone.

Implementation Plan

Commenters voiced concern over the implementation timelines and effective dates. MOD-033-1 is effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. This means that it is effective three years after approval, and the implementation plan further clarifies that the first 24 month period in the requirement starts on that date. Entities would need to have their plan complete by the effective date, but the obligation for completion of the periodic validation under Requirement R1 would essentially be five years after regulatory approval. For MOD-032-1, requirement R1 is effective approximately one year after approval, and the remaining requirements are effective approximately two years after approval.

VSLs

Commenters expressed concern that in the VSL section of MOD-032-1, the lower VSL seemed to state that perfect data submission (failed to submit 0% of required data) would result in a violation, which was defined as failure to submit 25% or less of the required data. The SDT clarifies that the VSL tables only determine the level of violation, not that a violation has occurred. Thus an entity that submits 100% of required data would not be in violation and the VSL tables would not be consulted. Only if a violation has occurred (submission of less than 100% of required data) are the VSL tables consulted to determine violation level.

There was also a comment on the severe VSL for MOD-032-1, Requirement R2 indicating confusion with the "failed to provide . . . within 30 . . . or did provide in greater than 75. . ." The SDT agrees and has corrected the VSL to align with the graduated approach in the other VSLs for the requirement.

One commenter suggested that the second condition under the Lower VSL for MOD-033-1, Requirement R1 should be qualified so the situation only applies when the time between the previous dynamic local event and the events occurred that required a simulation within 12 months exceeded 24 calendar months. The VSL has been modified to match the other changes to the requirement discussed earlier in this report.

Additionally, since there were changes to most requirements since the last posting, the VSLs were updated to reflect those changes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).

Description of Current Draft

This is the second posting of this standard for a 45-day formal comment period and ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-033-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
Final ballot	December 2013
BOT adoption	December 2013

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-1**

3. **Purpose: To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.**

4. **Applicability:**

   4.1. **Functional Entities:**

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct the standard be applicable to Planning Coordinators. The inclusion of the Transmission Planners in the applicability is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf.

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.

(Rationale continued on next page)

Rationale for R1: Continued

These suggested improvements in the proposed approach are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.

Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that “the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.”

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Rationale for R3: In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request, or a statement that it has not received written notification regarding technical concerns with the data submitted.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R3 in support of their respective Interconnection-wide case(s). While different entities in each of the three Interconnections create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for the Compliance Monitoring and Assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% or less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% or less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner (s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state,	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and

			dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR

			requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written

			response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required	The Planning Coordinator made available the required	The Planning Coordinator made available the required	The Planning Coordinator available the required data to

			data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	data to the ERO or its designee but failed to provide greater than 25% or less than or equal to 50% of the required data in the format specified by the ERO or its designee.	data to the ERO or its designee but failed to provide greater than 50% or less than or equal to 75% of the required data in the format specified by the ERO or its designee.	the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at 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.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
(provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as provided to the GO by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 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* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point*	8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

If a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. 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).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (~~Dates of posting TBD~~July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).

Description of Current Draft

This is the ~~first~~ second posting of this standard for a 45-day formal comment period and ~~initial~~ ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-033-1 ~~seek to~~ address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel ~~Initial~~ Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
~~Recirculation~~ Final ballot	~~September~~ December 2013
BOT adoption	~~November~~ December 2013

~~**Effective Dates**~~

~~In those jurisdictions where regulatory approval is required, Requirements R1 and R2 shall become effective on the first day of the fourth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the fourth calendar quarter after Board of Trustees approval, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after Board of Trustees approval.~~

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Version History

Version	Date	Action	Change Tracking
1	TBD	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**
2. **Number: MOD-032-1**
3. **Purpose: To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.**
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority~~ies~~

   4.1.2 Generator Owner~~s~~

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator~~s~~ (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner~~s~~

   4.1.6 Transmission Owner~~s~~

   4.1.7 Transmission Planner~~s~~

   4.1.8 Transmission Service Provider~~s~~

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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Comment [SN1]: The changes to the effective date language in the implementation plan are not material changes to the previously posted timelines. Rather, they are changes in effective date language format.

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MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~4.1.8~~

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~~5.~~6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires ~~a minimum level of~~ data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the ~~i~~Interconnection-wide case ~~model~~ building process in their ~~i~~Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

~~B.~~ Requirements and Measures

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the ~~steady state~~steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of ~~short-circuit~~short circuit data also required to perform ~~short-circuit~~short circuit studies. The addition of ~~short-circuit~~short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In ~~attempting to~~ developing a performance-based standard that would address the data requirements and reporting procedures for model data, ~~the MOD B informal standard development group found that~~ it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's ~~its~~ planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct the standard be applicable to Planning Coordinators. The inclusion of the Transmission Planners in the applicability is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

~~The requirement parts of Requirement R1 list the minimum set of items that must be included in the data requirements and reporting procedures developed by the Planning Coordinator.~~

~~Coordination between Planning Coordinators in the development of these requirements and reporting procedures is necessary in order to facilitate development of interconnection-wide models. While Requirement R1 does not require this coordination, Requirement R5 includes a requirement for the Planning Coordinators to submit model data for interconnection model building in the format specified by the ERO or its designee. It would likely be most efficient for Planning Coordinators to fashion their data requirements and reporting procedures with the interconnection-wide common format in mind.~~

(Rationale continued on next page)

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Rationale for R1: Continued

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf.

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.

These suggested improvements in the proposed approach are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, ~~and the collection of short-circuit data is also~~ consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

~~Data submitted to effectively model a transmission system is typically on a per-element(s) basis as the transmission system evolves. Therefore, the submittal of data, and the checking of data, is much simplified by submitting all parameters describing a specific element simultaneously, thus reducing the possibility for error in the data. Typically all data in some shape or form consists of steady-state, dynamic, and short-circuit related data and is used for these types of analysis.~~

~~The approach for the collection of data is done using an attachment approach.~~ The requirement uses an attachment approach to support data collection. The attachment specifically lists the ~~Responsible E~~entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required. ~~This attachment takes an "at-a-minimum" approach for the collection of data needed for the construction of the models specific to seasonal cases and specific cases and scenario and for an interconnection wide model that is not software specific. It includes data for steady-state, dynamics and short circuit. It clearly holds the Responsible Entities that have the data accountable for providing data.~~

Rationale for R1: Continued

Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

~~Rationale for R2:~~

~~An entity responsible for providing data under Requirement R3 has an obligation to submit data according to the data requirements and reporting procedures in its planning area developed under Requirement R1, and there may be cases, such as change of ownership, etc., that the submitting entity would need to request a copy of the data requirements and reporting procedures from its Planning Coordinator. This requirement ensures that the data requirements and reporting procedures developed under Requirement R1 by each Planning Coordinator are made available to an entity responsible for providing such data under Requirement R3.~~

R1. Each Planning Coordinator~~, in conjunction with~~ and each of its Transmission Planners~~,~~ shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for ~~its~~ the Planning Coordinator's planning area that include~~, including~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1; and

~~1.1. Specification of the required data that includes, at a minimum, the data listed in Attachment 1;~~

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s): ~~Specification of the d~~

~~1.2.~~1.2.1. Data format;

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~~1.3. Specification that the data must be shareable on an interconnection-basis to support use in the interconnection models;~~

~~1.4.~~1.2.2. ~~Specification of the l~~Level of detail to which equipment shall be modeled;

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~~1.5.~~1.2.3. ~~Specification of the c~~Case types or scenarios to be modeled; and

1.2.4. A schedule for submission ~~or confirmation~~ of data at least once every 13 calendar months.

~~1.6.~~1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.~~Examples of evidence include, but are not limited to, dated documentation or records that the required modeling data requirements and reporting procedures meet the specifications in Requirement R1.~~

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~~**R2.** Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**M2.** Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has distributed the requested data requirements and reporting procedures within 30 days of receiving a written request in accordance with Requirement R2; or a statement by the Planning Coordinator that it has not received a request for its data requirements and reporting procedures.~~

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Rationale for R2~~3~~:

~~The approach in this~~This requirement ~~to submit data to the Planning Coordinator~~ satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

~~It also accounts for areas where a BA may have more than one PC. It does not create a requirement for the Planning Coordinator or Transmission Planner, as entities receiving data. It does, however, allow for instances where a Transmission Planner may serve only as a conduit for the collection of data on behalf of functional entities if all parties mutually agree. The Responsible Entity required to supply the data in those cases is still accountable for the obligation to provide the data. In those instances, the intent of the requirement is not to change those established processes, but to reinforce and emphasize accountability for data provided by those entities that are in the best position to have correct data.~~

~~R3.~~R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~M3.~~M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data ~~Examples of evidence include, but are not limited to, dated documentation or records of submission by a registered entity of the required data (~~to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Rationale for R~~4~~3: In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform ~~power flow~~steady-state, dynamics, and ~~short-circuit~~short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that change~~s~~s on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

~~R4.~~R3. Upon ~~delivery~~ receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2~~3~~, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- ~~4.1.~~3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;
- ~~4.2. If requested by the notifying Planning Coordinator or Transmission Planner, provide additional dynamics data describing the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables; and~~
- ~~4.3.~~3.2. Provide the response within ~~30~~ 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

~~M4.~~M3. ~~Examples of evidence include, but are not limited to: dated records of a written request from the Transmission Planner or Planning Coordinator notifying a Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider regarding technical concerns, and additional evidence demonstrating the response to the request by the notified registered entity meets the specifications of Requirement R4~~Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request,~~;~~ or a statement ~~by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider~~ that it has not received written notification regarding technical concerns with the data submitted.

Rationale for R~~5~~4:

This requirement will replace MOD-014 and MOD-015

~~It~~ This requirement recognizes the differences among ~~i~~Interconnections in model building processes, ~~but~~and it creates an obligation for Planning Coordinators to ~~provide~~ make available~~the~~ data for its planning area ~~in a manner that accounts for those differences~~.

The requirement creates a clear expectation that Planning Coordinators will ~~provide~~ make available data that they collect under Requirement R3 in support of their respective Interconnection-wide case(s)~~interconnection models~~. While different entities in each of the three ~~i~~Interconnections create the ~~interconnection models~~Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each ~~i~~Interconnection to build the ~~interconnection-specific model~~specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s) ~~models~~, but only requires the Planning Coordinators to ~~submit~~ make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s);~~,~~ it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide ~~models~~cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide ~~models~~cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases ~~models~~. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each I~~i~~nterconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to ~~provide~~ make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases~~models~~.

~~R5.~~R4. Each Planning Coordinator ~~must~~ shall ~~submit~~ make available models for its planning area~~the~~ reflecting data provided to it under Requirement R2~~3~~ to the Electric Reliability Organization (ERO) or its designee to support creation of the ~~interconnection~~Interconnection-wide case ~~model~~(s) that includes the Planning Coordinator's planning area. ~~as follows:~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~5.1. In the format and according to the schedule specified by the ERO or its designee; and~~

~~5.2. Include documentation and reasons for data modifications, if any.~~

~~**M5.**~~ ~~Examples of evidence may include, but are not limited to, dated documentation or records indicating data submission from the Planning Coordinator to the ERO or its designee according to Requirement R5.~~Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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~~Regional Entity~~

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

~~The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.~~

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- ~~If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.~~
- ~~The CEA shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for the Compliance Monitoring and Assessment processes.~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints Text~~

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% or less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% or less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

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~~**R2**~~	~~**Long-term Planning**~~	~~**Medium**~~	~~The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them within 45 calendar days.~~	~~The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them within greater than 45 calendar days but less than or equal to 60 calendar days.~~	~~The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them within greater than 60 calendar days but less than or equal to 75 calendar days.~~	~~The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request or did provide in greater than 75 calendar days.~~
R2~~3~~	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s);

			than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator	greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR	greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider provided steady-state,

			Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and

						reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R~~3~~4	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within ~~30~~ 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within ~~45~~ 105 calendar days (or within 15 calendar	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within ~~30~~ 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than ~~45~~ 105 calendar days but less	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within ~~30~~ 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than ~~60~~ 120 calendar days but less	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within ~~30~~ 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).~~;~~ ~~OR~~ ~~The Balancing~~

			days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	than or equal to ~~60~~ 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	than or equal to ~~75~~ 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	~~Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider did provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 but not within greater than 75 calendar days (or within greater than 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).~~
R4~~5~~	**Long-term Planning**	**Medium**	The Planning Coordinator ~~submitted~~ made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format	The Planning Coordinator ~~submitted~~ made available the required data to the ERO or its designee but failed to provide greater than 25% or less than or equal to 50% of the required	The Planning Coordinator ~~submitted~~ made available the required data to the ERO or its designee but failed to provide greater than 50% or less than or equal to 75% of the required	The Planning Coordinator ~~submitted~~ available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO

			specified by the ERO or its designee.~~;~~ ~~OR~~ ~~The Planning Coordinator failed to provide the required data according to the schedule specified by the ERO or its designee but did provide the data within 15 calendar days after the specified date;~~ ~~OR~~ ~~The Planning Coordinator submitted the required data to the ERO or its designee but failed to include documentation and reasons for any data modifications.~~	data in the format specified by the ERO or its designee.~~;~~ ~~OR~~ ~~The Planning Coordinator failed to provide the required data according to the schedule specified by the ERO or its designee but did provide the data in greater than 15 calendar days but less than or equal to 30 calendar days after the specified date.~~	data in the format specified by the ERO or its designee.~~;~~ ~~OR~~ ~~The Planning Coordinator failed to provide the required data according to the schedule specified by the ERO or its designee but did provide the data in greater than 30 calendar days but less than or equal to 45 calendar days after the specified date.~~	or its designee.~~;~~ ~~OR~~ ~~The Planning Coordinator failed to provide the required data according to the schedule specified by the ERO or its designee and did not provide the data within 45 calendar days after the specified date.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

~~"At a minimum"~~ Data Reporting Requirements

The table, below, indicates the ~~"at a minimum"~~ information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	~~**short-circuit**~~**short circuit**
1. Each ~~B~~bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand ~~at each bus~~[2] [LSE] a. real and reactive power* b. in-service status* ~~c. load type (e.g., firm, interruptible, scalable, etc.)~~ 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	~~1.~~ Generator [GO, RP (for future planned resources only)] ~~a. Synchronous machines, including, as appropriate to the model:~~ ~~i. inertia constant~~ ~~i. damping coefficient~~ ~~i. saturation parameters~~ ~~i. direct and quadrature axes reactances and time constants~~ ~~b. Other technologies, including, as appropriate to the model:~~	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data ~~1. – provide for all applicable elements in column "steady-state" [GO, TO]~~ ~~2. Negative Sequence Data – provide for all applicable elements in column "steady-state" [GO, TO]~~

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), ~~Transmission Operator (TOP),~~ Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at 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.

[3] Including synchronous condensers~~,~~ and pumped storage~~, etc~~.

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steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**~~short-circuit~~short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). ~~d.~~ regulated bus* and voltage set point ~~e.~~d. ~~voltage set point~~* (as provided to the GO by the TOP) ~~f. owner(s) information (including percentage of ownership if jointly owned)~~ ~~g.~~e. machine MVA base ~~h. share of reactive contribution for voltage regulation*~~ ~~i.~~f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator ~~prime mover and fuel~~ type (hydro, wind, fossil, solar, nuclear, etc) ~~j.~~h. in-service status* 4. AC Transmission Line or Circuit ~~(series capacitors and reactors shall be explicitly modeled as individual line segments)~~ [TO] a. impedance parameters (positive sequence) ~~i. resistance~~ ~~ii. reactance~~ ~~iii.~~b. susceptance (line charging) ~~b.~~c. ratings (normal and emergency)* ~~c. equipment~~ in-service status* d. ~~5.~~ DC Transmission systems [TO] ~~– identified by DC line name or number [TO]~~ ~~a. AC bus number and name for each converter~~ ~~b. line parameters~~ ~~c. ratings~~ ~~d.~~5. ~~rectifier and inverter data~~ 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)*	~~i. inertia constant~~ ~~i. damping coefficient~~ ~~i. saturation parameters~~ ~~iv.~~1. ~~direct and quadrature axes reactances and time constants~~ 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE] ~~(consistent with system load representation (composite load model) and components as a function of frequency and voltage)~~ 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] ~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	~~3. Zero Sequence Data – provide for all applicable elements in column "steady-state" [GO,TO]~~ ~~a. Bus~~ ~~b. Generator~~ ~~c. Transmission line~~ ~~d. Transformer (to include connection type)~~ 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP] ~~4.~~

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steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**~~short-circuit~~short circuit**
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. regulated voltage limits or MW band limits*~~ g. ratings (normal and emergency)* h. in-service status* ~~h.~~ 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* e. in-service status* ~~d.~~ ~~e. share of reactive contribution for voltage regulation*~~ 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt ~~switching~~, if applicable d. in-service status* ~~c.~~ ~~d. share of reactive contribution for voltage regulation*~~ 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

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Application Guidelines

Guidelines and Technical Basis

If a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a ~~Transmission Planner~~TP may collect and aggregate some or all data from providing entities, and the ~~Transmission Planner~~TP may then provide that data directly to the ~~Planning Coordinator~~PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting ~~interconnection for~~connection of a new generator, the entity can determine who the PC is for that area at the time a generator ~~interconnection~~ connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the ~~three i~~Interconnections ~~(Eastern, ERCOT and WECC)~~. Presently, the Eastern/Quebec and Texas Interconnections ~~on an annual basis~~ build seasonal cases on an annual basis, while the ~~WECC~~ Western Interconnection builds cases on a continuous basis throughout the year. 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 ~~model~~(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case ~~model~~(s).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).

Description of Current Draft

This is the second posting of this standard for a 45-day formal comment period and ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-032-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
Final ballot	December 2013
BOT adoption	December 2013

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**

2. **Number: MOD-033-1**

3. **Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.**

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Standard MOD-

033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to the criteria listed without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

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;

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;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for the Compliance Monitoring and Assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the criteria specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1 the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator should consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 should include simulations that are to be compared with actual system data and may include comparisons of:

- Voltages oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Part 1.3 requires guidelines for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. For the power flow comparison, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or the guideline for voltage comparisons could be that it must be within 1%. But the guidelines should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.

The guidelines to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (~~Dates of posting TBD~~July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).

Description of Current Draft

This is the ~~first~~ second posting of this standard for a 45-day formal comment period and ~~initial~~ ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-032-1 ~~seek to~~ address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel ~~Initial~~ Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
~~Recirculation~~ Final ballot	~~September~~ December 2013
BOT adoption	~~November~~ December 2013

~~Effective Dates~~

~~In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after Board of Trustees approval.~~

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**
2. **Number: MOD-033-1**
3. **Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.**
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator~~s~~ (hereafter referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator~~s~~

   4.1.3 Transmission Operator~~s~~

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~5.~~6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-~~-~~011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires ~~a minimum level of~~ data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the ~~i~~Interconnection-wide case ~~model~~ building process in

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Comment [SN1]: The changes to the effective date language in the implementation plan are not material changes to the previously posted timelines. Rather, they are changes in effective date language format.

Formatted: Indent: Left: 0.65", Space Before: 0 pt, After: 6 pt their ~~i~~Interconnection. Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC-~~Planning~~ Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

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B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the ~~PC~~ Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system ~~for~~in the ~~steady state~~steady-state and dynamic models to compare performance against expected behavior or response~~within its area~~, which is consistent with the Commission directives. The validation of the full ~~interconnection model~~Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior ~~state estimator snapshot~~; and

B. ~~Simulation of significant system disturbances and comparing the simulation results with the actual event results~~Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to the criteria listed without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

~~Part 1.3 supports confirming or correcting the model for accuracy in coordination with the data owner when the actual system response does not match expected system performance, which could be accomplished through use of MOD-032-1, Requirement R4, if necessary.~~

R1. Each Planning Coordinator ~~must~~shall implement a documented data validation process ~~to validate the data used for steady state and dynamic analyses (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses~~ that includes the following attributes~~, at a minimum, the following items~~: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. ~~Validate its~~Comparison of the performance of the Planning Coordinator's portion of the existing system in ~~the~~ a planning power flow model ~~by comparing it~~ to actual system behavior, represented by a state estimator case or other Real-time data sources, ~~to check for discrepancies that the Planning Coordinator determines are large or unexplained~~ at least once every 24 calendar months through simulation;~~.~~

1.2. ~~Validate its~~ Comparison of the performance of the Planning Coordinator's portion of the existing system in ~~the~~ a planning dynamic model~~s~~ to actual system response, ~~at least once every 24 calendar months~~ through simulation of a dynamic local event, at least once every ~~, unless the time between dynamic local events exceeds~~ 24 calendar months. If ~~the time between~~no dynamic local ~~events exceeds~~event occurs within the 24 calendar months, ~~validate its~~ use~~portion of the system in the dynamic models through simulation of~~ the next dynamic local event that occurs;~~. Complete the simulation within 12 calendar months of the local event.~~

~~1.2.~~**1.3.** Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

~~1.3.~~**1.4.** Guidelines to~~Coordinate with the data owner(s) to confirm or correct the model for accuracy~~resolve differences in performance identified under Part 1.3 ~~when the discrepancy between actual system response and expected system performance is too large, as determined by the Planning Coordinator~~.

M1. ~~Examples of evidence may include, but are not limited to, a documented validation process and~~ Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual ~~real time~~ system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

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R2. Each Reliability Coordinator 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 ~~that the Planning Coordinator requests to~~ 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~1.1.~~ As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~Regional Entity~~

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1.2. Evidence Retention

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~~1.2.~~

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The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

~~The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.~~

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- ~~If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.~~

- ~~The CEA shall keep the last audit records and all requested and submitted subsequent audit records.~~

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for the Compliance Monitoring and Assessment processes.~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints Text~~

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; ~~The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 but did validate in less than or equal to 28 calendar months;~~ OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar	The Planning Coordinator documented and implemented a process to validate data but did not address ~~one~~ two of the ~~three~~ four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1;~~The Planning Coordinator documented and implemented a process to validate data but did not address two of the three required topics under Requirement R1;~~ OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar	The Planning Coordinator did not have a validation process at all or did not document or implement any of the ~~three~~ four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by ~~R1~~ part 1.1 within ~~or did validate but exceeded~~ 36 calendar months ~~between validation~~; OR The Planning Coordinator did not perform simulation as

			months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not ~~complete~~ perform simulation as ~~of the local event~~required by part 1.2 within ~~12~~ 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) ~~in validating its portion of the system in the dynamic models as required by R1~~ but did ~~complete~~ perform the simulation ~~in less than or equal to 15 calendar months~~within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months. ~~The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 but did validate in greater than 28 calendar months but less than or equal to 32 calendar months;~~ ~~OR~~ ~~The Planning Coordinator did not~~	months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.~~The Planning Coordinator did not validate its portion of the system in the power flow model as required by R1 but did validate in greater than 32~~	required by part 1.2 within 36 calendar months (or the next dynamic local event in cases where there is more than 24 months between events)~~The Planning Coordinator did not complete simulation of the local event at all in validating its portion of the system in the dynamic models as required by R1 or did complete the simulation but exceeded 18 calendar months~~.

				~~complete simulation of the local event within 12 calendar months in validating its portion of the system in the dynamic models as required by R1 but did complete the simulation in greater than 15 calendar months but less than or equal to 18 calendar months.~~	~~calendar months but less than or equal to 36 calendar months;~~ ~~OR~~ ~~The Planning Coordinator did not complete simulation of the local event within 12 calendar months in validating its portion of the system in the dynamic models as required by R1 but did complete the simulation in greater than 18 calendar months but less than or equal to 21 calendar months.~~	
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting ~~planning coordinator~~ Planning	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator~~planning~~	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator~~planning~~	The Reliability Coordinator or Transmission Operator did not provide ~~any~~ requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator~~planning~~

			Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	~~coordinator~~ within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 ~~calednar~~ calendar days but less than or equal to 60 calendar days.	~~coordinator~~ within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 60 calendar ~~calednar~~ days but less than or equal to 75 calendar days.	~~coordinator~~ within 75 calendar days; OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data. ~~The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting planning coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 calednar days but less~~

						~~than or equal to 60 calendar days.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Application Guidelines

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the criteria specified in the requirement. For further information on suggested validation procedures, see "Procedures for Validation of Powerflow and Dynamics Cases" produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is ~~encouraged~~ required to develop and include in its process ~~criteria~~ guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are ~~too large or unexplained~~unacceptable.

For the validation in part 1.1 the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be ~~utilized~~ used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies "once every 24 calendar months," entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator should consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator's planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole ~~i~~Interconnection.

The validation required in part 1.2 should include simulations ~~which~~ that are to be compared with actual system data and may include comparisons of:

- Voltages oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Application Guidelines

Part 1.3 requires guidelines for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. For the power flow comparison, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or the guideline for voltage comparisons could be that it must be within 1%. But the guidelines should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.

The guidelines to resolve differences in Part 1.4 could ~~be accomplished in~~include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3~~4~~ (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's ~~PC's~~ planning area, the model ~~to be used~~ for the validation should be one that contains a wider area of the ~~i~~Interconnection than the PC's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator ~~PC~~ should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's ~~PC's~~ area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). ~~If a model with estimated data or a generic model is used for a generator and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.~~ The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

October 7, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards
MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirement R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements

MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

~~July 18~~October 7, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards

MOD-032-1~~ – In those jurisdictions where regulatory approval is required~~, Requirement~~s~~ R1 ~~and R2~~ shall become effective on the first day of the ~~fourth~~ first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the fourth calendar quarter after Board of Trustees approval, and Requirements R3, R4, and R5 shall become effective on the first day of the eighth calendar quarter after Board of Trustees approval.~~

Comment [SN1]: The changes to the effective date language in the implementation plan are not material changes to the previously posted timelines. Rather, they are changes in effective date language format.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-033-1 ~~– In those jurisdictions where regulatory approval is required, this standard~~ shall become effective on the first day of the ~~twelfth~~ first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the twelfth calendar quarter after Board of Trustees approval.~~

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirement~~s R1 and~~ R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements

MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Unofficial Comment Form

Project 2010-03 Modeling Data

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft MOD-032-1 and MOD-033-1 standards. The electronic comment form must be completed by 8:00 p.m. ET on **November 20, 2013**

If you have questions please contact Steven Noess via email or by telephone steven.noess@nerc.net or 404-446-9691.

The project page may be accessed by clicking here.

Background Information

NERC Reliability Standards MOD-010 through MOD-015 address modeling data requirements that support the mathematical model representations of transmission, generation, and load that are the foundation of virtually all power system studies. Only two of those standards were approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Order No. 693. Four of them were neither approved nor remanded, and they remain in a pending status. Two new reliability standards are proposed. The proposal includes a combined modeling data standard to replace MOD-010 through MOD-015, MOD-032-1 (Data for Power System Modeling and Analysis), and a new validation standard to address directives related to validation, MOD-033-1 (Steady-State and Dynamic System Model Validation).

The Project 2010-03 Modeling Data Standard Drafting Team posted an initial draft of MOD-032-1 and MOD-033-1 for comment from July 22 to September 4, 2013. The drafting team revised the standards based on stakeholder recommendations, and changes made to the standards are redlined and accessible from the project page.

This posting solicits comment on the revised MOD-032-1 and MOD-033-1 standards. The standards respond to directives remaining from FERC Orders No. 693 and No. 890, and a summary of those directives with explanation of how the approach addresses them is available in the "Consideration of Issues and Directives" document on the project page.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Question

1. Proposed MOD-032-1 (Data for Power System Modeling and Analysis) consolidates and replaces the topics previously addressed by MOD-010 through MOD-015, in addition to incorporating improvements and approaches to meet remaining directives. In response to feedback from the last posting period, proposed MOD-032-1 has been revised to reflect that input while ensuring that the approach resolves the directives related to the project. Do you agree with the revisions? If not, please provide a specific alternative approach, and, if a directive applies, please articulate in detail how your suggested approach addresses the directive (a synopsis of each directive related to this project from FERC Orders No. 693 and No. 890 is available from the project page in the “Consderation of Issues and Directives” document).

☐ Yes
☐ No

Comments:

2. Proposed MOD-033-1 (Steady-State and Dynamic System Model Validation) addresses validation, in part to meet remaining directives related to validation. In response to feedback from the last posting period, proposed MOD-033-1 has been revised to reflect that input while ensuring that the approach resolves the directives related to the project. Do you agree with the revisions? If not, please provide a specific alternative approach, and, if a directive applies, please articulate in detail how your suggested approach addresses the directive (a synopsis of each directive related to this project from FERC Orders No. 693 and No. 890 is available from the project page in the “Consderation of Issues and Directives” document).

☐ Yes
☐ No

Comments:

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-032-1 and MOD-033-1
October 22, 2013

Introduction

The NERC Compliance department (Compliance) worked with the 2010-03 Modeling Data standard drafting team (SDT) to review the proposed standards MOD-032-1 and MOD-033-1. The purpose of the review was to discuss the requirements of the pro forma standards to obtain an understanding of their intended purposes and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the SDT in order to aid the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions should both assist the SDT in further refining the standard and serve as a tool to develop auditor training.

MOD-032-1 and MOD-033-1 Questions

Question 1

Under MOD-032-1 Requirement R1, how will the requirement for "(e)ach Planning Coordinator and each of its Transmissions Planners *shall jointly develop* . . . data requirements and reporting procedures . . ." be assessed for compliance? (Emphasis added).

Compliance Response to Question 1

During a compliance assessment, an auditor will look for evidence that the entities jointly developed the requirements and reporting procedures as required. In the absence of evidence demonstrating joint development, an auditor will not entertain arguments that one entity was cooperative and the other was not. Both entities will be assessed based on whether there was joint development. The auditor will note the results to be included in the next compliance assessment of the entity that was not currently being audited.

Evidence of joint development may include emails, drafts of data requirement documents or reporting procedures, meeting notes, phone records, or other evidence or attestations demonstrating agreement for the data requirements and reporting procedures.

Question 2

Under MOD-032-1 Requirement R2, will the auditor verify only that the data was delivered as specified, or will the auditor make a determination regarding whether the quality of the data is sufficient?

Compliance Response to Question 2

Based on the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified. This standard does not specify the criteria around quality, so auditors will not make any assessments in that regard.

Question 3

In MOD-033-1 Requirement R1, Part 1.3, is it clear what is meant by “unacceptable differencences in performance”?

Compliance Response to Question 3

Based on the language in the requirement and the purpose of the standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guidelines for how the Planning Coordinator will determine when and under what circumstances the performance comparisons conducted under Parts 1.1 and 1.2 result in “unacceptable differences.”

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the versions of the proposed standards requirements referenced in this document.

Attachment A

MOD-032-1 Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing data to the Planning Coordinator.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R3, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request; or a statement by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider that it has not received written notification regarding technical concerns with the data submitted.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R3 when requested by the ERO or its designee.

MOD-033-1 Requirements and Measures

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;

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;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

Consideration of Issues and Directives

Project 2010-03 – Modeling Data (MOD B)

October 7, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R3 provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by Project 2012-05 ATC Revisions (MOD A).

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific "at a minimum" data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as	FERC Order No. 693	See the response to Paragraph 1155.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	See the response to Paragraph 1148.
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission planner to provide fault and disturbance lists.		
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" This is being addressed by MOD-032, Requirement R3, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement R1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be	FERC Order No. 693	See response to paragraph 1210.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
validated against actual system responses.		

Consideration of Issues and Directives

~~MOD B~~Project 2010-03 – Modeling Data (MOD B)

~~Working Draft, July 9~~October 7~~1~~, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R3~~4~~ provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by Project 2012-05 ATC Revisions (MOD A)~~the MOD~~

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Issue or Directive	**Source**	**Consideration of Issue or Directive**
		~~A effort~~.
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the	FERC Order No. 693	See the response to Paragraph 1148.~~For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the~~

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Issue or Directive	**Source**	**Consideration of Issue or Directive**
entities required to list contingencies used to perform operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		~~directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.~~ ~~Transmission Operator has also been added as an applicable entity in MOD-032-1~~
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific "at a minimum" data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of	FERC Order No. 693	See the response to Paragraph 1155.

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Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission facilities and resource planning, as well as one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	See the response to Paragraph 1148.~~For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.~~
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct	FERC Order No. 693	**See the response to Paragraph 1148.~~For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the~~**

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Issue or Directive	**Source**	**Consideration of Issue or Directive**
the ERO to modify MOD-012-0 to require the transmission planner to provide fault and disturbance lists.		~~directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.~~ ~~For the second part of the directive, the Transmission Operator has been added as an applicable entity in MOD-032-1~~
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" This is being addressed by MOD-032, Requirement R34, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires

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estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		comparison of actual disturbance data to verify accuracy of dynamics models.
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement ~~1.1~~R1 addresses this directive, adding a

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be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing	FERC Order No. 693	See response to paragraph 1210.

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procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be validated against actual system responses.		

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Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-012-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-013-1, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R3	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, it provides a mechanism to obtain more accurate information and data in cases where the initial data provided may have technical or accuracy concerns, and it meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated “that ‘[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,’” but acknowledges “that, in certain circumstances, actual data may not be initially available and only obtained through ‘verification of the dynamic models with actual disturbance data.’” In those cases, additional detail regarding the data may be necessary.
NEW	MOD-032-1, R4	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective Interconnection-wide case(s).
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

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Project 2010-03 – Modeling Data (MOD B)

~~Working Draft (July 9, 2013) of~~October 7, 2013

Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R2~~3~~	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R2~~3~~	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators~~, in conjunction~~ with each of its Transmission Planners~~,~~ to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit ~~"at a minimum"~~data requirements.
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators~~, in conjunction~~ with each of its Transmission Planners~~,~~ to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit ~~"at a minimum"~~data requirements. MOD-032-1, Requirement R1~~2~~, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System

Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
MOD-012-0 R1	MOD-032-1, R2~~3~~	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R2~~3~~	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators~~, in conjunction~~ with each of its Transmission Planners~~,~~ to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit ~~"at a minimum"~~data requirements.

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators~~, in conjunction~~ with each of its Transmission Planners~~,~~ to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit ~~"at a minimum"~~data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution~~R2~~ maps to the portion of MOD-013-1, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support ~~submission of the data by~~ Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective ~~interconnections~~Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an ~~interconnection model~~Interconnection-wide case is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support ~~submission of the data by~~ Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective ~~interconnections~~Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an ~~interconnection model~~Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support ~~submission of the data by~~ Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective ~~interconnections~~Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an ~~interconnection model~~Interconnection-wide case is no longer necessary.
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support ~~submission of the data by~~ Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective ~~interconnections~~Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an ~~interconnection model~~Interconnection-wide case is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R~~3~~4	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, ~~part 3.2, which~~it provides a mechanism to obtain more accurate information and data in cases where the initial data provided ~~has~~ may have technical or accuracy concerns, and it meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated “that ‘[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,’” but acknowledges “that, in certain circumstances, actual data may not be initially available and only obtained through ‘verification of the dynamic models with actual disturbance data.’” In those cases, additional detail regarding the data may be necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R4~~5~~	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective ~~interconnection-wide models~~Interconnection-wide case(s).
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

DRAFT Reliability Standard Audit Worksheet[1]

MOD-032-1 – Data for Power System Modeling and Analysis

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X[3]							X	
R2	X		X			X				X		X			X
R3	X		X			X				X		X			X
R4							X[3]								

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" whiles the registration criteria lists "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include:

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Provide the modeling data requirements and reporting procedures that were developed. Provide evidence the data requirements and reporting procedures were jointly developed between the applicable Planning Coordinator and Transmission Planners which could consist of emails, meeting minutes, or the inclusion of the names of the jointly collaborating entities in any written procedures.

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-032-1, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence and verify procedures cover items listed in parts 1.1 through 1.3 for the Planning Coordinator's planning area.
Note to Auditor: Auditor will seek evidence that the specific data reporting requirements of each of the items in Attachment 1 are included in the developed data requirements and reporting procedures. Auditor will seek evidence that the entity jointly developed the requirements and reporting procedures as required. Entities will be assessed based on whether there was joint development. Joint agreement on data requirements and reporting procedures constitutes joint development. Evidence regarding the participation, or lack thereof, of an entity not under audit may be used as evidence of compliance at the time of such other entity's audit or other formal compliance monitoring process.	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence such as noted in M2.
Provide evidence that the data submitted meets the parameters of the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-032-1, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Determine if entity's data submissions match the requirements developed by its Planning Coordinator and

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	Transmission Planner. Based on auditor judgment, a sampling of data submissions may be used as opposed to the auditor examining the entire population of data submissions.
Note to Auditor: This standard does not specify criteria around quality of data, so auditors are not to make any assessments in that regard. Auditor will seek evidence that the data submitted meets the parameters of the data requirements and reporting procedures developed by its Planning Coordinator , including a sampling of steady state, dynamics and short circuit data as specified in Attachment 1. The auditor may also contact the applicable Planning Coordinator(s) or Transmission Planner(s) for additional confirmation that required modeling data was submitted according the developed procedures.	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows:

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request, or a statement that it has not received written notification regarding technical concerns with the data submitted.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[6]**:**

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M3.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-032-1, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R3) Review evidence provided to determine if any notifications were received by entity.
	(part 3.1) Review evidence to verify entity responded by updating data or providing an explanation with a technical basis for maintaining the current data.
	(part 3.2) Review evidence to determine if entity responded, per part 3.1, within 90 calendar days as outlined in the requirement.
Note to Auditor: Based on the auditor's judgment, he or she may inquire with entity's Planning Coordinator or Transmission Planner regarding whether any such notifications were made or simply confirm with the entity under audit.	

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Auditor Notes:

R4 Supporting Evidence and Documentation

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.

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to MOD-032-1, R4

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review evidence provided to determine if entity made models available to the ERO or its designee in accordance with the requirement.
Note to Auditor: Auditor should verify with personnel within the ERO, or its designee, regarding its requests made of the entity to support creation of the Interconnection-wide case(s). If ERO personnel inform that entity provided required information, then no further testing of this requirement is necessary.	

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC compliance, Standards	New Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

MOD-033-1 – Stead-State and Dynamic System Model Validation

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X[3]								
R2									X				X		

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" whiles the registration criteria lists "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes:

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;

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;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R1) Documented data validation process that addresses Parts 1.1 through 1.4.
(Part 1.1) Comparisons of performance as outlined in Part 1.1 as requested by auditor.
(Part 1.2) Comparisons of performance as outlined in Part 1.2 as requested by auditor.
(Part 1.3) Evidence of analysis summarizing results of comparisons outlined in Parts 1.1 and 1.2 against established guidelines.
(Part 1.3) Evidence of implementation of actions to resolve differences in performance identified under Part 1.3 summarizing actions taken.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed **(This section to be completed by the Compliance Enforcement Authority)**:

Compliance Assessment Approach Specific to MOD-033-1, R1
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Verify existence of a documented data validation process addressing parts 1.1 through 1.4.
	(Part 1.1) Review documented data validation process to verify it includes a provision for comparison of the existing system to actual system behavior per the requirements of Part 1.1 at least once every 24 calendar months. Review the entity's comparison(s) to determine that it was executed in accordance with its data validation process document and that it occurred at least once every 24 months.
	(Part 1.2) Review documented data validation process to verify it includes a provision for dynamic comparison of the existing system to actual system behavior per the requirements of Part 1.2 at least once during the timeframe established in Part 1.2. Review the entity's comparison(s) to determine that it was executed in accordance with its data validation process and that it occurred within the timeframe established in Part 1.2.
	(Part 1.3) Review documented data validation process to verify it includes guidelines to determine unacceptable differences in performance under Part 1.1 or 1.2. Review entity's analyses to gain reasonable assurance that it was executed as described in its data validation process document.
	(Part 1.4) Review documented data validation process to verify it includes guidelines to resolve differences in performance identified under Part 1.3. Also, review the analyses outlined in Part 1.3 to ascertain whether differences in performance identified resulted in actions being taken to address the differences.

Note to Auditor: Based on the language in the requirement and the purpose of the Standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guideline discussions about how the entity will determine when, and under what circumstances, the performance comparisons conducted under Parts 1.1 and 1.2 result in "unacceptable differences." Under part 1.3, an auditor will not assess the quality of the entity's guideline of what constitutes an "unacceptable difference," just that the validation process has been implemented and followed. Auditors will verify that any differences identified under part 1.3 were resolved per the entity's guidelines.

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.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator 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.

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, R2
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and reply) to determine if entity responded to information request(s) as required in Requirement R2 within 30 days of receiving a written request from any Planning Coordinator.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Planning Coordinators to determine if requests for data were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC compliance, Standards	New Document

Standards Announcement Reminder

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 and MOD-033-1

Additional Ballots and Non-Binding Polls now open through November 20, 2013

Now Available

Additional ballots for **MOD-032-1 and MOD-033-1** and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Wednesday, November 20, 2013.**

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards and non-binding polls of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results for **MOD-032-1 and MOD-033-1** will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller (via email),
Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 and MOD-033-1

Comment Period: October 7, 2013 – November 20, 2013

Upcoming:
Additional Ballots and Non-Binding Polls: November 8-20, 2013

Now Available

A 45-day formal comment period for **MOD-032-1 and MOD-033-1** is open through **8 p.m. Eastern on Wednesday, November 20, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, November 20, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined. During the initial comment period, two ballot pools were formed (one to ballot the standards and one for the non-binding polls). For this ballot and non-binding poll, each standard and its associated non-binding poll will be balloted separately (for a total of two standard ballots and two non-binding polls). The original ballot pools will be used for the individual standard ballots and non-binding polls.

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Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 and MOD-033-1

Comment Period: October 7, 2013 – November 20, 2013

Upcoming:
Additional Ballots and Non-Binding Polls: November 8-20, 2013

Now Available

A 45-day formal comment period for **MOD-032-1 and MOD-033-1** is open through **8 p.m. Eastern on Wednesday, November 20, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Wednesday, November 20, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined. During the initial comment period, two ballot pools were formed (one to ballot the standards and one for the non-binding polls). For this ballot and non-binding poll, each standard and its associated non-binding poll will be balloted separately (for a total of two standard ballots and two non-binding polls). The original ballot pools will be used for the individual standard ballots and non-binding polls.

Standards Development Process

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Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 and MOD-033-1

Additional Ballot and Non-Binding Poll Results

Now Available

Additional ballots for **MOD-032-1 and MOD-033-1** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, November 20, 2013.**

The standards received sufficient votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

	Ballot	Non-Binding Poll
	Quorum /Approval	Quorum/Supportive Opinions
MOD-032-1	79.05% / 73.46%	79.53% / 71.43%
MOD-033-1	79.84% / 69.42%	79.24% / 66.35%

Background information for this project, can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2010-03 MOD-032-1 (MOD B)
Ballot Period:	11/8/2013 - 11/20/2013
Ballot Type:	Additional Ballot
Total # Votes:	298
Total Ballot Pool:	377
Quorum:	**79.05 % The Quorum has been reached**
Weighted Segment Vote:	73.46 %
Ballot Results:	**The Ballot has passed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	104	1	57	0.722	22	0.278	1	5	19
2 - Segment 2	9	0.5	5	0.5	0	0	0	0	4
3 - Segment 3	80	1	44	0.71	18	0.29	0	4	14
4 - Segment 4	29	1	9	0.474	10	0.526	0	1	9
5 - Segment 5	90	1	50	0.758	16	0.242	0	3	21
6 - Segment 6	50	1	25	0.658	13	0.342	0	3	9
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.7	6	0.6	1	0.1	0	0	1
Totals	**377**	**6.7**	**201**	**4.922**	**80**	**1.778**	**1**	**16**	**79**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon		
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group CSU)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	COMMENT RECEIVED
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL/NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		

1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney's comment)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien NIPSCO)
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	

1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	San Diego Gas & Electric	Will Speer	Negative	NO COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Gropu - Colorado Springs

				Utilities)
3	ComEd	John Bee		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - FirstEnergy
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL)
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	COMMENT RECEIVED - Joe O'Brien NIPSCO
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		

3	Pacific Gas and Electric Company	John H Hagen		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments submitted by the SERC PSS)
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support the comments of FMPA)
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney		
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia

				Transmission Company GTC)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency - Frank Gaffney)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	COMMENT RECEIVED
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Bret Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado

				Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Abstain	
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bob Roddy (DPC))
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus	Abstain	
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Association)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	

5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (CSU)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports FirstEnergy Comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	

6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility	Diane J Barney	Affirmative	

	Commissioners			
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (submitted by SERC PSS/OC groups on 11/20/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2010-03 MOD-033-1 (MOD B) Ballot
Ballot Period:	11/8/2013 - 11/20/2013
Ballot Type:	Additional Ballot
Total # Votes:	301
Total Ballot Pool:	377
Quorum:	**79.84 % The Quorum has been reached**
Weighted Segment Vote:	69.42 %
Ballot Results:	**The Ballot has passed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	104	1	54	0.692	24	0.308	1	6	19
2 - Segment 2	9	0.6	5	0.5	1	0.1	0	0	3
3 - Segment 3	80	1	36	0.61	23	0.39	0	7	14
4 - Segment 4	29	1	10	0.526	9	0.474	0	2	8
5 - Segment 5	90	1	44	0.698	19	0.302	0	7	20
6 - Segment 6	50	1	22	0.595	15	0.405	0	4	9
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.7	6	0.6	1	0.1	0	0	1
Totals	**377**	**6.8**	**182**	**4.721**	**92**	**2.079**	**1**	**26**	**76**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon		
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Negative	COMMENT RECEIVED
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group CSU)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion has submitted comments for all 4 entities under one section to avoid duplication of comment)
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL/NextEra)

1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney's comment)
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien NIPSCO)
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	

1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	San Diego Gas & Electric	Will Speer	Negative	NO COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patricia Robertson)
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	SUPPORTS THIRD PARTY COMMENTS - (BC Hydro, Patricia

				Robertson)
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group - Colorado Springs Utilities)
3	ComEd	John Bee		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's Submitted comments)
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS- FirstEnergy
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL)
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		

3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	COMMENT RECEIVED - Joe O'Brien NIPSCO
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support the comments submitted by the SERC PSS)
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
				SUPPORTS

4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	THIRD PARTY COMMENTS - (Support the comments of FMPA)
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency - Frank Gaffney)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	COMMENT RECEIVED
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Bret Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		

5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Abstain	
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bob Roddy (DPC))
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACE'S)
5	EDP Renewables North America LLC	Mary L Ideus	Abstain	
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	

5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (CSU)

6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson		
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports FirstEnergy Comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		

6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (submitted by SERC PSS/OC groups on 11/20/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-Binding Poll Results

Project 2010-03 Modeling Data (MOD B)
MOD-032-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-03 MOD-032-1 (MOD B)
Poll Period:	11/8/2013 - 11/20/2013
Total # Opinions:	272
Total Ballot Pool:	342
Summary Results:	79.53% of those who registered to participate provided an opinion or an abstention; 71.43% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	COMMENT RECEIVED
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	

1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL/NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	COMMENT RECEIVED
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney's

				comment)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien NIPSCO)
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	San Diego Gas & Electric	Will Speer	Negative	NO COMMENT RECEIVED

1	SaskPower	Wayne Guttormson	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)

3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - FirstEnergy
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL)
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	

3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	COMMENT RECEIVED - Joe O'Brien
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support the comments submitted by the SERC PSS)
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		

3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support the comments of FMPA)
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Company GTC)
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency - Frank Gaffney)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	

4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Bret Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Abstain	
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bob Roddy (DPC))
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	

5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACE'S)
5	EDP Renewables North America LLC	Mary L Ideus	Abstain	
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	

5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Supports FirstEnergy Comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (submitted by SERC PSS/OC groups on 11/20/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2010-03 Modeling Data (MOD B)
MOD-033-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-03 MOD-033-1 (MOD B)
Poll Period:	11/8/2013 - 11/20/2013
Total # Opinions:	271
Total Ballot Pool:	342
Summary Results:	79.24% of those who registered to participate provided an opinion or an abstention; 66.35% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL/NextEra)
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney's comment)

1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	COMMENT RECEIVED
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien NIPSCO)
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Seattle City Light)
1	San Diego Gas & Electric	Will Speer	Negative	NO COMMENT RECEIVED
1	SaskPower	Wayne Guttormson	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	

3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - FirstEnergy
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS - (FPL)
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)

3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	COMMENT RECEIVED- Joe O'Brien - NIPSCO
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas and Electric)
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (I support the comments submitted by the SERC PSS)
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support the comments of FMPA)
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency - Frank Gaffney)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FirstEnergy)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Bret Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	SUPPORTS THIRD PARTY COMMENTS - (BC Hydro Patricia Robertson)
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS)
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Abstain	
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS

NERC

				THIRD PARTY COMMENTS - (Bob Roddy (DPC))
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus	Abstain	
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY

NERC

				COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	COMMENT RECEIVED
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Frank Gaffney)
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports FirstEnergy Comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	

6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (submitted by SERC PSS/OC groups on 11/20/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

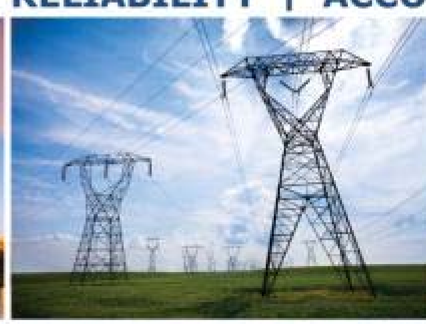
Consideration of Comments Summary

Project 2010-03 Modeling Data (MOD B) Standard Drafting Team

December 6, 2013

RELIABILITY | ACCOUNTABILITY



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Introduction

The 2010-03 Modeling Data Standard Drafting Team (SDT) thanks all participants for their feedback in finding ways to improve the proposed MOD-032-1 and MOD-033-1 Reliability Standards (MOD B standards). In response to the second formal posting of the standards, the SDT received input that was focused on the final issues that assisted the SDT in making final clarifications to the set of standards now posted. The SDT carefully considered all comments in determining whether to make particular changes to the standards, and this document is intended to provide a summary explanation of the SDT's deliberations.

These standards were posted for a 45-day public comment period from Monday, October 7, 2013, to Wednesday, November 20, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 54 sets of comments, including comments from approximately 163 different people from approximately 105 companies representing 9 of the 10 Industry Segments.

Furthermore, the SDT wishes to thank the industry for their significant engagement and support throughout the project. Industry participants and observers, whether formally or informally, and whether in person or through other means, provided important perspectives and subject matter expertise that facilitated the SDT's consideration of the complicated issues and technical matters reflected in these standards. It was a collaborative process that reflected the significant dedication of the individuals in our committed industry.

At this stage, the drafting team has reached a point where it has made a good faith effort at resolving applicable objections, and it has not made any substantive changes to MOD-032-1 since posting draft 2. Therefore, the team is posting MOD-032-1 and its corresponding implementation plan for a final ballot. Because of one possible substantive change in MOD-033-1, explained in this document, MOD-033-1 is posted for an additional 45-day comment period and concurrent ballot. As in past drafts of MOD-032-1 and MOD-033-1, the SDT thoroughly considered proposed changes and evaluated them carefully by considering several important variables, such as, but not limited to, whether such changes were in the interest of reliability, whether they would improve or reduce consensus, whether they had unintended consequences for other types of entities, and whether they were in support of the SDT's obligation to respond to regulatory directives, most notably from FERC Order No. 693. The SDT has done its best to be responsive to all inputs, recognizing that it is not possible to adopt every suggestion given the considerable diversity of entities to which the standards will apply.

During the posting of the second draft of the proposed MOD-32-1 and MOD-033-1 Reliability Standards, the drafting team asked questions related to the approach in each of the standards. As a whole, the SDT found that the responses were thoughtful, organized, and focused.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Vice President and Director of Standards Mark Lauby at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Consideration of Comments

MOD-032-1

Commenters provided input on several items related to MOD-032-1, with some items commented upon more frequently than others. In this section, the SDT provides response to most of those items individually, followed by discussion of the remaining items.

Changes Since Draft 1

Several commenters continue to support the consolidation of the existing MOD-010 through MOD-015 standards into MOD-032-1, and they provided support for several of the specific changes described in the consideration of comments document for draft 1. The SDT appreciates the support and thanks the commenters for the input.

"Jointly Develop" concerns for Requirement R1

Some commenters expressed concern with the change in Requirement R1 for Planning Coordinators (PC) and Transmission Planners (TP) to "jointly develop" steady-state, dynamics, and short-circuit modeling data requirements and reporting procedures for the PC's planning area. The specific concern was a compliance concern for one entity being subject to actions by another in this joint development.

The SDT appreciates this concern and discussed the language as proposed. In draft 1 of MOD-032-1, the requirement language required that "Each Planning Coordinator, *in conjunction with* each of its Transmission Planners, shall develop . . . data requirements and reporting procedures." (Emphasis added). However, the industry response through comments overwhelmingly did not support an approach on the basis that it gave too much discretion to the Planning Coordinator. Similar to the approach in TPL-001-4, the SDT modified the requirement to focus on joint development between the Transmission Planners and Planning Coordinator for each planning area. This change reflects the SDT's understanding of the vast majority of entities, and further discussion and deliberation underscored support for the language. The requirement as written does not specify how the entities must jointly develop the data requirements and reporting procedures, and provides for several alternatives to accomplish the requirement (whether by agreement, committee, delegation, etc). Multiple PCs and TPs may collectively sign on to a set of data requirements and reporting procedures that would cover their respective areas to accomplish "joint development."

A commenter for both MOD-032-1 and MOD-033-1 indicated concern with applicability to the PC or that they do not have a PC, which creates concern for them in submitting to both the TP and PC in Requirement R2. The commenter suggests alternative language for Requirement R2 to focus on submitting to either the TP or the PC, and additionally asserts that, for the Western Interconnection, WECC should collect the data and there should be a WECC variance. On the first issue, the SDT notes the language from the guidance section of MOD-032-1: "If a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data)." On the second issue, the SDT notes below in greater detail the continued reason for including PC to meet the directive language, along with why the standard is not applicable to to the Regions.

Coordination with Other Standards

There were some comments that repeated the already addressed concerns from the previous comment period regarding perceived duplication with other standards (MOD-025, MOD-026, MOD-027, IRO-010-1, and TOP-

003). The SDT response remains the same as that provided under the comment response from draft 1 on October 7, 2013, which is described in detail on pages 5 and 6 that comment report. MOD-025 was newly commented upon during draft 2 on this issue, and the rationale as explained for the other standards (that they are for different purposes, and the information provided could be different information), remains apt for MOD-025 as well. MOD-025 requires *verification*, and MOD-032 is focused on obligations between and among entities regarding *submission* of data in support of the Interconnection-wide case(s)). Furthermore, other commenters supported the SDT's position by stating that the SDT added "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." The SDT agrees and thanks the commenter for that statement.

User-written Models

Some commenters suggest that user-written models should be forbidden or prohibited, and they have concern that the standard provides permission to submit user-written models (a primary argument from commenters against "user written" models is that they are not easily converted from, for example, PSS/E software over to PSLF software that companies use). Other concerns included perceived weakening of the advancements in precluding the use of user-written models in certain areas today, and that the standard as written could potentially erode that progress.

The SDT understands the concerns and wants to reiterate that it agrees that user-written models should be used rarely, if at all. MOD-032-1 is not intended to encourage the use of user-written models, and the jointly developed data requirements and reporting procedures under Requirement R1 may provide details for how a user-written model may or may not be employed. In any case, attachment 1 specifies certain essential information that is required when a user-written model is used. The SDT also notes that Requirement R1, part 1.2 prescribes that certain specifications in the data requirements and reporting procedures must be consistent with procedures for building the Interconnection-wide case(s), including data format. Additionally, the SDT discussed that as new technology evolves, there may be instances where a standard model is not available, and the information must come from a user-written model. Therefore, the SDT did not make a change, as the additional information required for user-written models as specified in attachment 1 provides a reasonable mechanism to support reliability by ensuring that additional information and characteristics will accompany each user-written model until a standard library model is available.

Distribution Provider Applicability

Some commenters suggested that certain items should also be applicable to Distribution Providers to provide data for facilities less than 100 kV, load forecast data for use in model development, and short circuit data for transformer connections to the transmission system that serves network subtransmission facilities.

The SDT confirms that the load data contemplated by the standard is that data provided by the Load Serving Entity function, and it did not make the change. While the SDT understands that certain subtransmission information is useful in certain cases, it is outside the scope of applicability of this standard unless those facilities are part of the Bulk Electric System (BES).

Balancing Authority Applicability

Some commenters asked that the SDT consider the removal of Balancing Authority (BA) as an applicable entity because the only reference to BA in Attachment 1 (data reporting requirements for steady state, dynamics, and short circuit) is in the item for "Other Information Requested by the PC or TP necessary for modeling purposes." The commenters suggest that 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.

In response, the commenters are correct that as a matter of course most data requirements or reporting procedures in MOD-032 would not require data from BAs. The SDT did discuss the issue at length, and at first glance the SDT thought removing BA from the applicability of MOD-032 would not be a reliability concern.

However, the SDT originally included BAs on the basis that they may have certain information regarding interchanges that affect the powerflow cases, especially for BAs that are not ISOs. Coordination of load and resources in the models with the areas corresponding to them is important as well, and the SDT continues to believe BA input may be necessary in certain cases. Furthermore, removing BAs from applicability at this time would require modification of the standard at a later date through the standards development process if additional information is necessary in the future. The SDT notes the concern regarding BA applicability was not widespread, and it was not raised at all during the comment period for draft 1 of the standard. The SDT also reiterates that the primary focus of this project is not only addressing improvements and recommendations related to the existing set of standards, but also addressing remaining directives from FERC Order No. 693. Several directives related to this project underscore the Commission's concern that analysis of the Interconnection system behavior requires the use of accurate models, and leaving BA out of applicability may leave a potential gap in that analysis.

Short Circuit Data

Some commenters continued to request that the SDT not include short-circuit data in MOD-032-1. Some suggested that short-circuit data should not be required by the standard or that there is not a need for an Interconnection-wide short-circuit model.

The SDT notes this was an issue also raised in response to draft 1, and the SDT reaffirms its previous discussion that "the directive from FERC Order No. 890, paragraph 290, specifically requires inclusion of short circuit data. Having the short circuit data as part of this standard supports that information being shareable on an interconnection basis, particularly to support analysis at the seams, and it supports TPL-001-4, Requirement R2, which requires the Transmission Planner (TP) and PC to include a short circuit analysis as part of its annual assessment."

In addition, its inclusion here does not necessarily mean that the information would be used in a power flow case or in an Interconnection-wide case. It could also be used to provide equivalence information at the seams.

Older Unit Concerns

Some commenters raised concern surrounding treatment of detailed data for older units, and that estimated data should be allowed in certain cases.

Under Requirement R1, part 1.2.2, the data requirements and reporting procedures must specify the level of detail required that is consistent with Interconnection-wide procedures, and in this manner, the standard addresses the commenters' concern and provides a mechanism to allow estimated data for such older units. As noted in the response to comments from draft 1, "the standard as written does allow submission of estimated/typical data – and at the same time does not preclude submission of unit-specific data. More detailed stipulations can be included in the specific PC/TP procedures as necessary."

Assignment of the Interconnection-wide Case

Some commenters correctly note that MOD-032-1 does not assign who builds the Interconnection-wide case or provide a requirement for the ERO to provide the models. Other comments indicated suggestions for minor changes to the wording of Requirement R4 to the "designated Interconnection-wide Data Base Group and to the ERO on request." Similarly, one commenter suggested there should be an additional requirement for the ERO or its designee to submit model data requirements and reporting procedures to the PCs for data consistency and data reporting timeliness.

MOD-032-1 is not a standard for building the Interconnection-wide case, however. It is a standard that outlines the obligations surrounding submission of data by various entities in support of analysis of the interconnected transmission systems. The focus of the standard is on data owners and Planning Coordinators supporting Interconnection-wide case building processes in their respective Interconnection while creating a framework to support ERO designation of an entity to build the actual Interconnection-wide case. The ERO has an interest in ensuring successful completion of the Interconnection-wide cases for each interconnection, and that interest and obligation is outside the scope of MOD-032-1. Rather than specify Interconnection-wide case building responsibilities in MOD-032-1, the standard is a part of and supports that larger ERO commitment. In MOD-032-1, the Planning Coordinator's obligation is to make information available for use in the Interconnection-wide case(s), and that obligation remains and is measurable regardless of whom they are making that information available to.

On the issue of changing the wording of R4, the SDT discussed at length, and notes that the language in Requirement R4 was heavily coordinated to reach a consensus point. Given the purpose of the requirement and the support for the current wording, changes to the language as suggested may not support the consensus position, and the SDT did not adopt them.

RSAW Comments

There were some specific comments on the associated Compliance Input document and the Reliability Standards Audit Worksheets (RSAW) developed by NERC compliance operations with input from the SDT and posted for information during the comment period. The SDT notes that the RSAW is not part of the standard ballot, and it is outside the scope of the SDT. The SDT will forward the specific comments regarding the RSAWs to NERC Compliance Operations for their review, and they expect they will be considered in working to finalize the RSAW.

Attachment 1 comments

Several individual comments included suggestions to add specificity or additional items in certain criteria in attachment 1. The SDT determined that the existing language in the attachment provides appropriate information, and additionally notes that the PC/TP procedures could specify more details around how to provide the information in response to the comments. The SDT reviewed Attachment 1 in considerable detail between posting drafts 1 and 2 of the standards, and revised Attachment 1 to focus on the information necessary to support the Interconnection-wide case(s). These changes resulted in increased consensus and to find a balance between specificity and consistency. Furthermore, several of the recommended inclusions to attachment 1 are not regarded as essential to Interconnection-wide case(s) or related to reliability (e.g., some parameters suggested are used for other reasons such as cost allocation or other purposes), and the SDT intends to ensure that inclusion of attachment 1 parameters supports the purpose of MOD-032-1.

A commenter was concerned that the phrase 'Other information requested by ....' in Attachment 1 is too open ended, and the commenter was concerned that it provides "a route for requesting copious amounts of modeling data, for powerflow, dynamics, or short-circuit models, and wasting valuable resource time." The SDT understands the concern, but it notes that the purpose and scope of the standard limits that item under Attachment 1. To the extent something is requested that is in addition to the items previously listed, it must be necessary to support the Interconnection-wide case(s), not just additional information that is unrelated to the purpose of the standard or used for other means.

Other comments suggested including items 2, 3, and 4 under dynamic data as subparts under item 1, as they only apply to synchronous generators. The SDT did not make the change because in some cases (e.g., certain wind units), these items may apply to other resource types.

Some commenters suggested that the GO item in attachment 1 to provide regulated bus and voltage set points is covered by VAR-001-2 or that the TOP or GOP should be subject to the standard instead. The SDT ultimately does not agree. First, with respect to item 3 overall, the GO, as the owner, should know certain characteristics about its units, and it is reasonable to expect them to know this information. There is also a distinction between the reason and purpose for the required action in the VAR standards. The fact that VAR-001 requires TOPs to provide GOPs certain information is for operations purposes that can change more readily, and is to support knowing operational bands. In the VAR context, it has operating implications. For planning purposes (the time horizon of this standard), that information is much more static. Thus, the SDT believes that it is reasonable to expect a GO to provide the information as part of the larger suite of generator unit information. It may require coordinating with their GOP or other parties, or it could involve the GO, as the owner, ensuring that its operator provide this information to the GO. Or, the GO could communicate with its TP. Further, the SDT was trying to provide the parenthetical in earlier drafts (that was not commented on) to note that "regulated bus" and "voltage set point" were not arbitrary data the GO determines. However, to clarify the item, the SDT modified the parenthetical slightly to clarify that the information is required to be known by the GO (without specifying how it must know it) and to remove the misunderstood expectation that they must get the information directly from their TOP. With respect to adding the GOP or the TOP to the standard, the SDT determined that those functions are not appropriate for inclusion in this standard.

A commenter also suggested that Resource Planners (RP) are not appropriate to provide future information and that the GO should be responsible. The SDT disagrees; in many cases, the RP is the entity that identifies the need for future generation, and a GO may not yet exist for that planned resource to provide the information.

A commenter suggested adding a caveat to MOD-032-1's attachment 1 exempting nuclear units from validating reactive power by staged performance testing. In response, those units are still expected to provide capabilities, and that is all that this standard requires. Other standards address individual unit capability verification.

A commenter asks for clarification of "all applicable elements" in the short circuit column. The SDT reviewed this suggestion and determined that applicable elements may vary. The short circuit column also makes specific reference to the elements in the "steady-state" column.

A commenter notes that VAR-002-2b already requires certain transformer data to be provided to the TOP and TP, but the SDT notes that the purpose and context of those requirements are different. While some information may be the same, VAR-002-2b only requires that information be sent to the TP upon a request for the information, and MOD-032-1 supports providing that data to the TP and PC for use in the Interconnection-wide case(s).

Commenters provided specific suggestions for addition or removal of entities from applicability of certain items in attachment 1, to include whether BA, LSE, or TSP should be provided in certain instances, particularly in the "other items necessary for . . ." criteria. Commenters also suggested flexibility to account for how data or information is collected in certain instances. Similar to the explanation for BA applicability, above, analysis of Interconnection system behavior requires use of accurate models, and removing these entities from applicability in the instances suggested may leave a gap in that analysis. With respect to how information is collected, the functions listed are still generally responsible for the information, and alternative arrangements for collection are contemplated and explained in greater detail in MOD-032-1's Guidelines and Technical Basis section.

A few commenters suggest that attachment 1 is too prescriptive and provide alternative examples. The SDT made several significant changes in previous drafts to remove specificity from attachment 1 to limit it to those necessary for reliability while also ensuring a balance to account for other entities desiring greater specificity. The commenter provided suggestions to add to the explanation that the asterisk could also mean that the items have no data. The SDT was concerned that such addition could unintentionally result in entities not providing data that they should have in certain cases. Instead, the SDT reviewed the items under item 7 for reactive compensation and clarified that certain of the items are only applicable if mode of operation is not fixed. The commenter also suggested that regulated voltage band limits may vary, and the SDT agrees and has added an asterisk. Finally, the commenter suggested that "Demand" is unclear under the Dynamics column's item 5, and that it should be clarified to "Demand classification" with an explanatory footnote. The SDT changed this item in response to comment during a previous draft to remove such specificity, and it notes that such additional detail could be clarified by individual procedures under Requirement R1.

One commenter asked the SDT to provide modifications to attachment 1 to provide more specificity around "Gross Minimum Real Power," "normal plant configuration," and "In-service status." The SDT discussed these parameters, and similar to other suggestions for greater specificity, such additional detail could be clarified by individual procedures under Requirement R1. Providing greater specificity in the Reliability Standard itself could unintentionally restrict various modeling configurations. The SDT also notes that the phrase "normal plant configuration" was added specifically in response to comments from previous drafts.

A commenter asked for clarification whether the parenthetical caveat "for future planned resources only" under "[GO, RP (for future planned resources only)]" applies only to the RP function, and the SDT confirms that the caveat as used is intended to apply only to RP.

A commenter asks for clarification on which generator units are subject to Attachment 1. The SDT references previous commentary on this question from the October 7, 2013, response to comments at page 7 on "Facilities," noting the limitations to the scope and jurisdiction of reliability standards. Specifically, the SDT noted, "While such data is not precluded to be modeled, it is outside the scope of the reliability standard itself. Such data is typically provided through other existing procedures or arrangements."

A commenter suggested that additional dispersed forecast Demand data be added to MOD-032-1 (that was previously in MOD-016), with additional clarifications in the footnote. However, consistent with ensuring that the information in attachment 1 supports various differences across the continent, such additional detail is best clarified by individual procedures under Requirement R1, not by increased specificity in attachment 1. Furthermore, the footnote at reference already specifies that the Demand contemplated "is the Demand aggregated at each bus."

A commenter suggested including synchronous condensers to attachment 1, and the SDT notes that they are specified in attachment 1 (see footnote 3).

Other Specific Comments

Commenters also raised several other items that were not directly related to the issues already identified and discussed, above, and a summary of those comments and the SDT's consideration is provided in this section.

One commenter provided suggested edits to the gradations provided for in the VSLs for Requirement R 1 to correct them for consistency. The SDT agrees with the edits and has made the correction.

A commenter provided concern (in both MOD-032-1 and MOD-033-1) regarding two specific items in the Compliance section of the standard, noting that there are capitalized references to "Applicable Entity" which are not defined terms and requesting that the SDT list the applicable processes in the "Compliance Monitoring and Assessment Processes" part instead of referring to those in the NERC Rules of Procedures (ROP). The commenter states that the reference to a process found in the NERC ROP may be an issue for some Canadian entities in particular who have their own Compliance and Monitoring program and have only adopted select aspects of the NERC ROP. In response, the SDT agrees with the capitalization suggestion and has made the change. The SDT has also made a change to modify references to the NERC ROP in response to the second concern. Section 1.3 of that section does not mandate the use of a specific ROP process (i.e., it does not require that NERC's Compliance Monitoring and Enforcement Program (CMEP) be used); rather, the language simply refers to the processes described in the ROP that may be used to monitor and assess compliance with the standard.

Some commenters suggested some minor additions or wording changes. One commenter suggested adding the words ‘a registered entity shall submit’ after the words ‘last submission’ for requirement R2. One commenter suggested changing ‘current data’ to ‘data already submitted’ for requirement R 3.1. The SDT reviewed each suggestion, but did not make changes, as the phrases as written are reasonably well-understood, and the SDT did not want to introduce changes that may affect others’ understanding to negatively impact maintaining consensus.

A commenter suggested modifying the reference to ‘within 90 calendar days of the request’ to ‘within 90 calendar days of written notification’ in measurement M3. The SDT reviewed the measure and it has made a clarifying change to synchronize the measure with the requirement language.

One commenter suggested adding a time or frequency requirement to Requirement R4, but the SDT believes that the obligations in Requirement R4 are clear without requiring specific time or frequency parameters.

One commenter raised concern regarding Requirement R4 by asserting that it has the potential to put a resource burden on a PC to provide a potentially unknown number of models to the ERO to support Interconnection-wide cases they want to create. The SDT attempted to provide a framework that will work on a continent-wide basis to support Interconnection-wide case building processes. The SDT understands this concern and gave this serious consideration, but in many respects, it is outside the scope and purpose of the standard.

One commenter raised concerns over PCs developing different procedures, which may lead to inconsistent procedures. The SDT discussed this issue, and it notes that PCs may have different procedures, but the type of data required by attachment 1 provides a level of consistency. Additionally, as the SDT noted in its consideration of comments posted on October 7, 2013, “The SDT . . . added clarification to Requirement R1 that PCs must create their data requirements and reporting procedures jointly with TPs, and the requirement is more specifically linked to support Interconnection-wide modeling to address inconsistency concerns.”

Some commenters suggested that the following phrase should be moved to the measure for Requirement R2: ”...For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.” The SDT considered this during the previous comment period and indicated that it was a significant item for building consensus. The SDT also continues to understand that it is more than a measure, but a further qualification of the requirement language to positively indicate the performance expectations under the requirement.

For Requirement R4, a commenter suggested a rewording of the specific requirement language related to making models available to the ERO or its designee. Rather than “to support creation of the Interconnection-wide case(s),” the commenter suggested that it should refer instead to “the compilation of submitted data to form new Interconnection-wide base cases.” The SDT does not believe that this suggestion adds specific clarity over what is already present. At this stage, changing the language could cause more confusion than it resolves, or negatively affect already established consensus, and it did not make the change.

One commenter suggested that the standard should require in Requirement R4 that the PCs, in making models available for use in the Interconnection-wide case(s), be “independent” Planning Coordinators to prevent any submission of equipment or system representation data that can influence base case simulation results. The SDT notes that the obligation under the requirement is to make models available that reflects data it received.

One commenter does not agree with the need to characterize the PC in the requirements as a combination of Planning Coordinators and Planning Authorities, as noted in the applicability section, given that version 5 of the Functional Model does not include “Planning Authority” as a functional entity. As explained in the applicability section and in response to comments from the last posting period, the purpose of that characterization is to account for current differences between the NERC registration criteria and the NERC functional model.

One commenter believes there is insufficient linkage between Requirements R1 and R5 for the Eastern Interconnection and also suggests developing separate standard for each Interconnection. The SDT notes that Requirement R5 from draft one was changed significantly and renumbered to Requirement R4 in draft two, and it believes that the comment may be addressing a previous draft. If it was not in reference to the previous draft, the SDT does believe there is a linkage between Requirements R1 and R4 because of Part 1.2. Part 1.2 requires that the data requirements and reporting procedures developed under Requirement R1 provide specifications of data format, level of detail, and case types and scenarios must be consistent with procedures for building the Interconnection-wide case. The SDT does not believe that a separate standard is necessary for each Interconnection and that this standard strikes the appropriate balance of consistency of data types (through attachment 1) while also supporting a framework that recognizes certain differences among the Interconnections.

A commenter noted that the Application Guide discusses the SDT intent to not require a change to present data collection efforts, and the commenter notes that short circuit models are currently handled via the Regional Entity, not the Planning Coordinator. The SDT understands this concern, but notes the standards applicability to Regional Entities (previously RRO) is, in part, why FERC did not approve them in Order No. 693. Additionally, that order contained directives to add PCs. With the exception of some changes in responsibility, the SDT does continue to believe that, in general, data collection efforts or procedures do not necessarily need to change extensively as a result of the standard, but it acknowledges that they may. The standard provides a framework that is durable and should not require standards modifications to support changing processes, methods, or organizational structures going forward.

A commenter suggested that MOD-032-1 requires data collection that meets the Paragraph 81 criteria, and that such information should be linked to mandatory data request instead of through a standard. This issue was raised in the first comment period as well, and the SDT addressed this issue in its response to that draft. The SDT ensured that the requirements in the proposals were results-based and considered criteria from the Paragraph 81 project (Project 2013-02 Paragraph 81). The SDT considered the criteria from the Paragraph 81 project to ensure that the standards proposals did not create requirements that meet those criteria. The Paragraph 81 project also prepared a "Paragraph 81 Project Technical White Paper," dated December 20, 2012, that includes discussion of the identifying criteria that must be satisfied before a Reliability Standard requirement may be proposed for retirement.[2] Specifically, for a Reliability Standard requirement to be proposed for retirement, it must satisfy *both* the overarching criterion that it requires an activity or task that does little, if anything, to benefit reliability *and* additional identifying criteria (such as criteria that it is administrative, reporting, redundant, etc., as discussed in the Paragraph 81 Technical White Paper).[3] Importantly, with respect to modeling, providing modeling data itself supports reliability objectives. The paragraph 81 identifying criterion for administrative requirements (criterion B1) applies when the requirement "requires responsible entities to perform a function that is administrative in nature, *does not support reliability* and is needlessly burdensome."[4] Similarly, the identifying criterion for reporting requirements (criterion B4) applies to requirements that obligate responsible entities to report to a Regional Entity, NERC, or another party or entity "on activities *which have no discernible impact on promoting the reliable operation of the BES* and if the

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[2] *Paragraph 81 Project Technical White Paper*, December 20, 2012. Available at http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20RF/P81_Phase_I_technical_white_paper_FINAL.pdf.

[3] See *Id.* at p. 7 and 8.

[4] *Id.* at p. 8. (Emphasis added).

entity failed to meet this requirement there would be little reliability impact."[5] Absence of modeling data for use in the Interconnection models would be expected to have a reliability impact, and the requirements in MOD-032-1 do not create requirements that meet the Paragraph 81 criteria because they establish consistent modeling data requirements and reporting procedures to support analysis of the reliability of the interconnected transmission system.

MOD-033-1

Much like MOD-032-1, commenters provided input on several items related to MOD-033-1, with some items commented upon more frequently than others. In this section, the SDT provides response to most of those items individually, followed by discussion of other items from the comment report.

Dynamic Local Event Timing Clarification

One commenter stated that for Requirement R1, part 1.2, there is no specific timeframe given in which the comparison should be completed after the event if the event does not occur within the first 24 months, which could lead to concerns that an auditor could expect it to be done more quickly than is possible. The SDT reviewed the requirement in response to the comment and agrees that some might benefit from additional clarity of intent in part 1.2. In response, the SDT confirms that the intent of the requirement is to complete comparison using a dynamic local event within 24 months of the last dynamic local event used in comparison and to complete each comparison within 24 months of the dynamic local event. The SDT has rephrased part 1.2 to clarify the intent of the requirement to ensure that it is clear that PC will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison, and that is not what is intended by the requirement. In addition, the SDT provides expanded discussion of the timeline for that part in the "Guidelines and Technical Basis" section of the standard to underscore the requirement part's intent. While the SDT views this addition as a general clarification of the timeframes expected by Part 1.2, the clarification it provides may be viewed by some as substantive. Therefore, rather than proceed to final ballot on MOD-033-1, an additional ballot will occur because of this change.

Inconsistent Procedures

Some commenters expressed concern that the large number of PCs may lead to inconsistent validation procedures. MOD-033-1 is focused on the procedures of how a PC will conduct comparisons of the information within its area. The commenters are correct that not every PC would necessarily conduct their comparisons in the same manner. The SDT notes that the focus of MOD-033-1 is not on Interconnection-wide disturbances, and it is therefore not necessary that the procedures be the same. The SDT also provides many suggested ways to perform comparison under this standard in the Guidelines and Technical basis section, and the SDT determined that final decisions regarding specificity of procedure should be left to the PC's judgment. The SDT also believes that, while individual procedures may be different, the outcomes of such comparisons (validation of data) would be consistent.

Period Between Validations

Commenters suggested that the 24 months timeline in Requirement R1 is too frequent. As alternatives, various commenters suggested making the timeline 36 months, 5 years, or 10 years. The SDT continues to support its comments in response to this issue from the first posting, and it believes 24 months represents the consensus position: "The SDT clarifies that the "local dynamic event" does not have to be a severe event requiring a large amount of set-up, but could be much smaller events that if done frequently over time would validate portions of the model in each 24 month period. The SDT also provided greater explanation of "dynamic local event" in the background section of the standard. In response to concern that validation every two years will be a large

[5] *Id.* at p. 9. (Emphasis added).

engineering effort, the SDT notes that the requirements are focused on planning area validation, and it leaves a lot of decisions regarding validation to the discretion of the PC."

"Paragraph 81" Criteria Concern

A commenter suggested that Requirement R2's requirement for RCs and TOPs to provide data to the PC in certain circumstances violates the "Paragraph 81" criteria (for a more in-depth discussion of "Paragraph 81" criteria as it relates to this project, please see the October 7, 2013, comment response document for draft 1, and discussion regarding the same issue for MOD-032-1, above). The commenter suggested Requirement R2 meets Paragraph 81 criteria because it is administrative, focuses on data collection activities, and requires periodic updates that do not directly support reliability. The SDT disagrees. The Paragraph 81 criteria addresses "requirements that obligate responsible entities to report to a Regional Entity, NERC, or another party or entity "on activities *which have no discernible impact on promoting the reliable operation of the BES* and if the entity failed to meet this requirement there would be little reliability impact." (Emphasis added). The SDT does not agree that Paragraph 81 is invoked since providing such information for use in performing comparisons under MOD-033-1, Requirement R1 "[promotes] the reliable operation of the BES" and that there would be a "reliability impact" if such information is not provided.

Generator Owner or Transmission Owner Applicability

Some commenters suggested adding either or both the Generator Owner (GO) and Transmission Owner (TO) to Requirement R2's applicability. In response, the type of data that the GO or TO may have, such as PMU or DFR data, would generally be available at the RC or TOP, and the SDT did not add the GO or TO functions to the applicability for MOD-033-1. Furthermore, if comparison under MOD-033-1 highlights a technical concern with data already provided for the existing system used for planning purposes from a GO or TO, MOD-032-1, Requirement R3 provides the means to coordinate those concerns with a GO or TO. For purposes of MOD-033-1, Requirement R2, the focus is on actual system behavior data the RC or TOP is expected to have to compare with planning data the PC already has.

Requirement R1 "Guidelines"

Some commenters asked for clarification about what is meant by "guidelines" in Requirement R1. The SDT sees this question as potential confusion over whether the word "guidelines" in the requirement is supposed to be guidelines the PC develops for itself as part of the procedure, or whether it refers to guidelines that exist outside the context of the standard. Another commenter expressed concern that different PCs could create different guidelines, resulting in different results. One commenter suggested that the guidelines under parts 1.3 and 1.4 be specified in the standard, not left to the PC. The two references to guidelines in Parts 1.3 and 1.4 are mandatory attributes that must be included in the PC's documented process. The SDT also changed references from "criteria" to "attributes" in the rationale and Guidelines and Technical basis section to make clear that it is referring to the attributes required by Parts 1.1 through 1.4. The main requirement language in Requirement R1 requires a PC to implement a documented validation process. That process must include the attributes listed under 1.1 through 1.4. The "guidelines" referenced in parts 1.3 and 1.4 to be in a PC's process are not the same as the "Guidelines and Technical Basis" section of the standard, though a PC could certainly incorporate concepts from that discussion into its documented process. The SDT also notes that the "Guidelines and Technical Basis" section of the standard is not mandatory and enforceable, and does not itself create requirements. With respect to consistency, the SDT agrees that the guidelines could vary, and notes the discussion, above, under the "inconsistent procedures" heading. The SDT also made clarifying changes in the "Guidelines and Technical Basis" section to explain Parts 1.3 and 1.4 require the PC to include certain guidelines in its documented validation process. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both.

What Models

Some commenters asked the SDT to clarify "what models" (or, alternatively, some commenters suggested the standard addresses the wrong models; that issue was discussed in great detail in the October 7, 2013, comment response to draft 1). Some entities suggested that the requirement should focus on only near term (year one) models, and that the standard should be more specific about which models are the focus of the requirement. Other commenters continued to suggest that MOD-033-1's focus on planning models is incorrect and that the operations models should be validated. In response to specifying year-one models, the SDT believes that the language in the requirement is clear with reference to "existing system." The SDT considered further specifying "year-one" models, but that could potentially preclude the PC's use of other, more useful models for a particular comparison. The SDT did not make a change for those reasons.

In response to the comments that the operational models should be validated instead of the planning models, the SDT notes that the purpose of the standard is to support increased accuracy of the planning models, and the FERC directives applicable to this project (see related "Consideration of Issues and Directives" document of the project page) are also in the context of the planning models. The state estimator already uses an operational model, so comparing that model may not result in a meaningful comparison from the perspective of improving planning models. There is, however, potential for a significant discrepancy between planning models and actual system behavior.

Other Specific Comments

Commenters also raised several other items that were not directly related to the issues already identified and discussed, above, and a summary of those comments and the SDT's consideration is provided in this section.

One commenter suggested that for MOD-033-1, Requirement R1, it should be required that the PCs be "independent," because the requirement places the responsibility for implementation of a documented data validation process on the PC. The SDT did not fully understand what was intended by this concern, but notes that the requirement applies to each PC to implement a documented data validation process for its own planning area. The PC could request input into developing its process, but the PC is independently responsible under the requirement.

One commenter suggested that specific requirements for the guidelines in Requirement R1, parts 1.3 and 1.4 need to be spelled out to address concerns that Requirement R2 may impose an excess burden on the TOP to provide data to the PC. The SDT does not believe that an excessive burden will be placed on the TOP. Requirement R2 only requires the TOP to provide any real time data that it has for a specific event or disturbance, and the TOP does not have to identify or otherwise conduct the comparisons under Requirement R1.

Another commenter states that Requirement R2 requires an entity to provide data that, in some cases, it is not required to have. Requirement R2 states, in part, that "Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (*or a written response that it does not have the requested data*)." (Emphasis added). If the TOP or RC does not have the data, it is not required to provide any data.

Several commenters expressed concern that 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 SDT agrees that it could take a large number of dynamic local events to cover the entire PC's area, especially for the larger PCs, but the SDT does not see that as an issue. The intent of the SDT was to use smaller local events for the comparisons so that the data requirement for the comparisons would be less and the need for data from another Planning Coordinator would be less. If it takes a large number of these comparisons, it may just take a longer period of time to complete.

One commenter asserted that MOD-033-1 will be very burdensome to the industry with little benefit. As this standard addresses local phenomena, not Interconnection-wide events, the SDT does not believe that the effort to make the required comparisons for dynamic local events will be burdensome. A local event will not require a significant amount of data or time to accomplish, and it is required only every 24 months.

Some commenters suggest that MOD-033-1 is generally vague and generic, and the commenters suggest there needs to be more clarity regarding which cases should be benchmarked and what parameters of the case will be evaluated. Another commenter indicated that the phrase “unacceptable difference” should be clarified in Requirement R1, part 1.3, and that the SDT needs to provide quantitative or qualitative factors for acceptability of the required comparisons. The SDT intentionally left many details of the comparisons up to the judgment of the PC, so long as the process meets the established attributes laid out in Requirement R1’s parts. As a results-based standard, the SDT focused on describing what result is expected (comparisons to real-time data) compared to prescribing in too much detail how to accomplish the result.

One commenter suggested allowing for an extension of the 30 day timeframe in Requirement R2 for providing actual system behavior data, as long as all parties involved agree to the time extension. The SDT continues to believe that the data required by Requirement R2 is readily available and that 30 days is an appropriate time frame.

Another commenter suggested that there are issues not yet well addressed by the industry in order to perform “consistent validation”. These are, according to the commenter: a) typical or estimated data models, b) generic data models, and c) proprietary data models. The SDT believes that typical, estimated, or generic models should reasonably represent the behavior of the devices that they represent. If they do not, then the comparisons performed by the PC will indicate that the parameters of the model should be modified. Furthermore, the SDT notes that there is no requirement to submit proprietary (user-written) models, and if agreements do not allow sharing the proprietary model, the expectation is for the data owner to submit a generic or standard model that is shareable and that represents the behavior of the device. Should there be a need to use proprietary models, those will need to be supplemented with proper documentation, as noted in MOD-032-1’s Attachment 1.

One commenter expressed a concern for the lack of clarity concerning who their PC is. The SDT agrees that entities need to know who their PC is. The SDT also notes that the Guidelines and Technical Basis section at the end of MOD-032-1 gives guidance on how to determine who the PC is, and Regional Entity registration staff should also be able to assist.

One commenter asked when the 24 month interval begins for Requirement R1, parts 1.1 and 1.2. The SDT intends for the 24 month interval to begin on the date that the standard becomes effective as determined from the information in the Effective Date section and as described in greater detail in the implementation plan, which states, “MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, “. . . at least once every 24 calendar months . . .”, and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.”

One commenter suggested that in Requirement R1, part 1.4 – “differences” should be clarified to “unacceptable differences” to be consistent with the “unacceptable differences” it references in part 1.3 of the requirement. The SDT agrees and has made the change.

Another commenter suggested that in Requirement 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. The SDT agreed that the Measure should be consistent with the requirement, and it has changed the language in the measure such that it conforms to the language in the requirement.

One commenter suggested that in Requirement R2, the words 'from such Planning Coordinator' should follow 'written request'. The SDT believes the intent as written is clear and reasonably understood, and it did not see the need for that addition.

One commenter stated that as the complexity of the component models increase, so does the likelihood of non-convergence at the system level. The commenter also suggests that it may take several iterations before a good approximation is reached (and may not converge under all operating scenarios), and the commenter believes a reasonable risk-based approach to compliance should be used to account for the uncertainty in the technology. The SDT agrees that non-convergence could be an issue in some instances, but it believes that PCs may account for those scenarios in their data validation processes. Possible compliance approaches is a topic largely outside the scope of the SDT.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).
4. Third posting for a 45-day comment period and concurrent ballot (December 2013).

Description of Current Draft

This is the third posting of this standard for a 45-day formal comment period and ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-032-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
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Additional 45-day Formal Comment Period with Parallel Ballot	December 2013
Final ballot	January 2014
BOT adoption	February 2014

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**

2. **Number: MOD-033-1**

3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their

Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

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.

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 (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs.

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2.

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see "Procedures for Validation of Powerflow and Dynamics Cases" produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies "once every 24 calendar months," entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator's planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltages oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language provides that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, in the event that more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a “month 23” dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator’s planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator’s area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator’s area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator’s area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Standard Development Timeline

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Development Steps Completed

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None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**

2. **Number: MOD-033-1**

3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as “Planning Coordinator”)

   This proposed standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their

Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives ~~(to include several remaining directives~~ from FERC Order No. 693~~)~~, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS~~at~~ whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the ~~criteria~~ attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

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.~~;~~

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 (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs.~~;~~

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2.~~; and~~

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator ~~who has indicated a need for the data for validation purposes~~performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The ~~Applicable Entity~~applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an ~~Applicable Entity~~applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to ~~Section 3.0 of Appendix 4C of~~ the NERC Rules of Procedure for ~~the~~ a list of ~~Compliance Monitoring and Assessment~~compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the ~~criteria~~ attributes specified in the requirement. For further information on suggested validation procedures, see "Procedures for Validation of Powerflow and Dynamics Cases" produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies "once every 24 calendar months," entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator ~~should~~ may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator's planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 ~~should~~ may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltages oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of "at least once every 24 calendar months" is intended to both provide for 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language provides that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, in the event that more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a "month 23" dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event's occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event's occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

October 7, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards
MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirement R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements

MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Unofficial Comment Form

Project 2010-03 Modeling Data

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft MOD-033-1 standard. The electronic comment form must be completed by 8:00 p.m. ET on **January 21, 2014.**

If you have questions please contact Steven Noess via email or by telephone steven.noess@nerc.net or 404-446-9691.

The project page may be accessed by clicking here.

Background Information

NERC Reliability Standards MOD-010 through MOD-015 address modeling data requirements that support the mathematical model representations of transmission, generation, and load that are the foundation of virtually all power system studies. Only two of those standards were approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Order No. 693. Four of them were neither approved nor remanded, and they remain in a pending status. Two new reliability standards are proposed. The proposal includes a combined modeling data standard to replace MOD-010 through MOD-015, MOD-032-1 (Data for Power System Modeling and Analysis), and a new validation standard to address directives related to validation, MOD-033-1 (Steady-State and Dynamic System Model Validation).

The Project 2010-03 Modeling Data Standard Drafting Team posted an initial draft of MOD-032-1 and MOD-033-1 for comment from July 22 to September 4, 2013. The drafting team revised the standards based on stakeholder recommendations, and changes made to the standards are redlined and accessible from the project page.

This posting solicits comment on the revised MOD-033-1 standard. The standards respond to directives remaining from FERC Orders No. 693 and No. 890, and a summary of those directives with explanation of how the approach addresses them is available in the "Consideration of Issues and Directives" document on the project page.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Question

1. In draft 2 of proposed MOD-033-1 (Steady-State and Dynamic System Model Validation), Requirement R1, part 1.2, required "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." In response to comments, the SDT agreed that some might benefit from additional clarity of the SDT's intent in part 1.2. In response, the SDT confirms that the intent of the requirement is to complete comparison using a dynamic local event within 24 months of the last dynamic local event used in comparison and to complete each comparison within 24 months of the dynamic local event. The SDT has rephrased part 1.2 to clarify the intent of the requirement to ensure that it is clear that a PC will not face a timing scenario that makes it impossible to comply. Specifically, the SDT added language to clarify that the reference of "at least once every 24 calendar months" means that the PC must "use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event." This was the only change in the standard that may be substantive. Do you agree with the clarification? If not, please provide suggested alternative clarifications.

☐ Yes
☐ No

Comments:

Consideration of Issues and Directives

Project 2010-03 – Modeling Data (MOD B)

October 7, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R3 provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by Project 2012-05 ATC Revisions (MOD A).

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific “at a minimum” data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as	FERC Order No. 693	See the response to Paragraph 1155.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	See the response to Paragraph 1148.
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission planner to provide fault and disturbance lists.		
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated “that ‘[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,’” but acknowledges “that, in certain circumstances, actual data may not be initially available and only obtained through ‘verification of the dynamic models with actual disturbance data.’” This is being addressed by MOD-032, Requirement R3, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement R1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be	FERC Order No. 693	See response to paragraph 1210.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
validated against actual system responses.		

Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-012-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3’s inclusion of specifications for distribution maps to the portion of MOD-013-1, Requirement R2 to “make the data requirements and reporting procedures available on request.”

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R3	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, it provides a mechanism to obtain more accurate information and data in cases where the initial data provided may have technical or accuracy concerns, and it meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" In those cases, additional detail regarding the data may be necessary.
NEW	MOD-032-1, R4	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective Interconnection-wide case(s).
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

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Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-032-1 and MOD-033-1
October 22, 2013

Introduction

The NERC Compliance department (Compliance) worked with the 2010-03 Modeling Data standard drafting team (SDT) to review the proposed standards MOD-032-1 and MOD-033-1. The purpose of the review was to discuss the requirements of the pro forma standards to obtain an understanding of their intended purposes and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the SDT in order to aid the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions should both assist the SDT in further refining the standard and serve as a tool to develop auditor training.

MOD-032-1 and MOD-033-1 Questions

Question 1

Under MOD-032-1 Requirement R1, how will the requirement for "(e)ach Planning Coordinator and each of its Transmissions Planners *shall jointly develop* . . . data requirements and reporting procedures . . ." be assessed for compliance? (Emphasis added).

Compliance Response to Question 1

During a compliance assessment, an auditor will look for evidence that the entities jointly developed the requirements and reporting procedures as required. In the absence of evidence demonstrating joint development, an auditor will not entertain arguments that one entity was cooperative and the other was not. Both entities will be assessed based on whether there was joint development. The auditor will note the results to be included in the next compliance assessment of the entity that was not currently being audited.

Evidence of joint development may include emails, drafts of data requirement documents or reporting procedures, meeting notes, phone records, or other evidence or attestations demonstrating agreement for the data requirements and reporting procedures.

Question 2

Under MOD-032-1 Requirement R2, will the auditor verify only that the data was delivered as specified, or will the auditor make a determination regarding whether the quality of the data is sufficient?

Compliance Response to Question 2
Based on the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified. This standard does not specify the criteria around quality, so auditors will not make any assessments in that regard.

Question 3
In MOD-033-1 Requirement R1, Part 1.3, is it clear what is meant by “unacceptable differencences in performance”?

Compliance Response to Question 3
Based on the language in the requirement and the purpose of the standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guidelines for how the Planning Coordinator will determine when and under what circumstances the performance comparisons conducted under Parts 1.1 and 1.2 result in “unacceptable differences.”

Conclusion
Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the versions of the proposed standards requirements referenced in this document.

Attachment A

MOD-032-1 Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing data to the Planning Coordinator.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R3, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request; or a statement by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider that it has not received written notification regarding technical concerns with the data submitted.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R3 when requested by the ERO or its designee.

MOD-033-1 Requirements and Measures

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;

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;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

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DRAFT Reliability Standard Audit Worksheet[1]

MOD-033-1 – Stead-State and Dynamic System Model Validation

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	Audit
Names of Auditors:	Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X[3]								
R2									X				X		

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

[3] This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" whiles the registration criteria lists "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes:

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;

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. (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R1) Documented data validation process that addresses Parts 1.1 through 1.4.
(Part 1.1) Comparisons of performance as outlined in Part 1.1 as requested by auditor.
(Part 1.2) Comparisons of performance as outlined in Part 1.2 as requested by auditor.
(Part 1.3) Evidence of analysis summarizing results of comparisons outlined in Parts 1.1 and 1.2 against established guidelines.
(Part 1.3) Evidence of implementation of actions to resolve differences in performance identified under Part 1.3 summarizing actions taken.

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Verify existence of a documented data validation process addressing parts 1.1 through 1.4.
	(Part 1.1) Review documented data validation process to verify it includes a provision for comparison of the existing system to actual system behavior per the requirements of Part 1.1 at least once every 24 calendar months. Review the entity's comparison(s) to determine that it was executed in accordance with its data validation process document and that it occurred at least once every 24 months.
	(Part 1.2) Review documented data validation process to verify it includes a provision for dynamic comparison of the existing system to actual system behavior per the requirements of Part 1.2 at least once during the timeframe established in Part 1.2. Review the entity's comparison(s) to determine that it was executed in accordance with its data validation process and that it occurred within the timeframe established in Part 1.2.
	(Part 1.3) Review documented data validation process to verify it includes guidelines to determine unacceptable differences in performance under Part 1.1 or 1.2. Review entity's analyses to gain reasonable assurance that it was executed as described in its data validation process document.
	(Part 1.4) Review documented data validation process to verify it includes guidelines to resolve differences in performance identified under Part 1.3. Also, review the analyses outlined in Part 1.3 to ascertain whether differences in performance identified resulted in actions being taken to address the differences.

Note to Auditor: Based on the language in the requirement and the purpose of the Standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guideline discussions about how the entity will determine when, and under what circumstances, the performance comparisons conducted under Parts 1.1 and 1.2 result in "unacceptable differences." Under part 1.3, an auditor will not assess the quality of the entity's guideline of what constitutes an "unacceptable difference," just that the validation process has been implemented and followed. Auditors will verify that any

differences identified under part 1.3 were resolved per the entity's guidelines. 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.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator 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.

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and reply) to determine if entity responded to information request(s) as required in Requirement R2 within 30 days of receiving a written request from any Planning Coordinator.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Planning Coordinators to determine if requests for data were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

<u>Revision History</u>

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC Compliance, Standards	New Document
2	1/8/2013	NERC Compliance, Standards	Changed language of Requirement 1 Part 1.2 to match new version of the Reliability Standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-03 Modeling Data (MOD B)
MOD-033-1

Additional Ballot and Non-Binding Poll Now Open through January 21, 2014

Now Available

An additional ballot for **MOD-033-1 – Steady-State and Dynamic System Model Validation** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is open through **8 p.m. Eastern on Tuesday, January 21, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting
Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or by telephone at 404-446-2560.

Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 and MOD-033-1

Final Ballot for MOD-032-1: December 6-16, 2013
Comment Period for MOD-033-1: December 6, 2013 – January 21, 2014

Upcoming:
Additional Ballot and Non-Binding Poll for MOD-033-1: January 10-21, 2014

Now Available

A final ballot for **MOD-032-1** is open through **8 p.m. Eastern on Monday, December 16, 2013.** A 45-day formal comment period for **MOD-033-1** is open through **8 p.m. Eastern on Tuesday, January 21, 2014.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **MOD-033-1** is open through **8 p.m. Eastern on Tuesday, January 21, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An additional ballot for **MOD-033-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-03 Modeling Data (MOD B) MOD-032-1 and MOD-033-1

Final Ballot for MOD-032-1: December 6-16, 2013
Comment Period for MOD-033-1: December 6, 2013 – January 21, 2014

Upcoming:
Additional Ballot and Non-Binding Poll for MOD-033-1: January 10-21, 2014

Now Available

A final ballot for **MOD-032-1** is open through **8 p.m. Eastern on Monday, December 16, 2013.** A 45-day formal comment period for **MOD-033-1** is open through **8 p.m. Eastern on Tuesday, January 21, 2014.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **MOD-033-1** is open through **8 p.m. Eastern on Tuesday, January 21, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An additional ballot for **MOD-033-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as previously outlined.

Standards Development Process

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Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-033-1

Additional Ballot and Non-Binding Poll Results

Now Available

A ballot for **MOD-033-1 – Steady-State and Dynamic System Model Validation** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, January 22, 2014.**

The standard achieved a quorum and received sufficient votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results	Non-Binding Poll Results
Quorum: 76.92% Approval: 81.41%	Quorum: 75.73% Supportive Opinions: 80.68%

Background information for this project, can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Ballot Results	
Ballot Name:	Project 2010-03 MOD-033-1 (MOD B)
Ballot Period:	1/10/2014 - 1/22/2014
Ballot Type:	**Additional Ballot**
Total # Votes:	290
Total Ballot Pool:	377
Quorum:	**76.92 % The Quorum has been reached**
Weighted Segment Vote:	81.41 %
Ballot Results:	**The ballot has closed.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	104	1	60	0.845	11	0.155	0	9	24
2 - Segment 2	9	0.8	7	0.7	1	0.1	0	0	1
3 - Segment 3	80	1	48	0.828	10	0.172	0	6	16
4 - Segment 4	29	1	10	0.667	5	0.333	0	4	10
5 - Segment 5	90	1	43	0.796	11	0.204	0	11	25
6 - Segment 6	50	1	32	0.8	8	0.2	0	4	6
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.1	1	0.1	0	0	0	0	3
9 - Segment 9	3	0.1	1	0.1	0	0	0	0	2

10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**377**	**6.8**	**209**	**5.536**	**47**	**1.264**	**0**	**34**	**87**

Individual Ballot Pool Results				
Segment	**Organization**	**Member**	**Ballot**	**NERC Notes**
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports FirstEnergy Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien - NIPSCO)
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	COMMENT RECEIVED
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	

1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson		
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Don Idzior)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	COMMENT RECEIVED
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		

3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jea)
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	

4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Don Idzior)
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative Corporate Compliance Dept.)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	

5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Don Idzior)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy's Comments)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF-SRT)
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	

5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support someone else's comment: Thomas Foltz – American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (First Energy's)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	

6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be provided by Seminole's Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-Binding Poll Results

Project 2010-03 Modeling Data (MOD B)
MOD-033-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-03 MOD-033-1 (MOD B)
Poll Period:	1/10/2014 - 1/22/2014
Total # Opinions:	259
Total Ballot Pool:	342
Ballot Results:	75.73% of those who registered to participate provided an opinion or an abstention; 80.68% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		

1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports FirstEnergy Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municpal Power Agency)
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	

1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien - NIPSCO)
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Don Idzior)
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger	Affirmative	

3	FirstEnergy Corp.	Cindy E Stewart	Negative	COMMENT RECEIVED
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jea)
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	

3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Don Idzior)
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative Corporate Compliance Department)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Don Idzior)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		

5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF-SRT)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	

5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (First Energy's)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be provided by Seminole's Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	

8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (32 Responses)
Name (19 Responses)
Organization (19 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (0 Responses)
Comments (32 Responses)
Question 1 (31 Responses)
Question 1 Comments (32 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Individual
Thomas Foltz
American Electric Power
No
After further review, AEP now believes that R2 is too open-ended in both data requested and potential format, especially given that only 30 days is being afforded to provide that data. MOD-032-1 added the text “unless a longer time period is agreed upon” to allow flexibility, and we believe similar verbiage should be added to MOD-033-1 as well. AEP disagrees with the response given by the team in its consideration of comments where it states that providing the data would not be unduly burdensome as it “only requires the TOP to provide any real time data that it has for a specific event or disturbance…”. As written, the requirement provide no bounds on what data could be requested, nor in what format. As a result, some requests could conceivably be quite burdensome and/or too difficult to provide within thirty days. The recommended text would provide the flexibility necessary for both parties to agree on the amount of time needed to provide the data. In addition, AEP believes that performing comparisons every 24 months is unnecessarily excessive, and instead recommends the period be established as 60 months. Due to the concerns provided, and after further consideration, AEP has decided to vote negative on this proposed standard.
Individual
Lance Bean
Consumers Energy Company

No
The measurement R1 does not provide enough guidance. Here are some quotes from R1 that demonstrate what I mean ‘does not prescribe a specific method or procedure for the validation’, ‘the outcome is left to the judgment of the Planning Coordinator’ , ‘entities are encouraged to perform the comparison on a more frequent basis’, the Planning Coordinator may consider among the other criteria’ ‘ may include comparisons of'. In summary, MOD-0330-1 as written is too vague. For this reason, the Consumers Energy ballot body is voting negative on MOD-033-1.
Individual
John
Falsey
Yes
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Individual
David Jendras
Ameren
Yes
We believe that this clarification should address concerns regarding the impossibility of collecting data and completing an analysis for a dynamic local event occurring in month 23 since the previous dynamic local event.
Individual
Brett Holland
Kansas City Power & Light
No
Although I appreciate the drafting team’s attempt at clarification of the standard, I believe that further modifications are necessary. First, I question why the clarification was inserted in parentheses and the placement of the clarification in general. Also, I have additional concerns regarding the following situation: Dynamic local event A occurs and the Planning Coordinator, according to R1.2, initiates the comparison of the model to actual system response. Dynamic

local event B occurs the following month. There are no additional dynamic local events in the following 23 months. In this situation, the comparisons would have to be almost concurrent, forcing the Planning Coordinator to do twice as many comparison as otherwise required. Also, if the Planning Coordinator decided to wait to see if another event occurred within the 24 month period after event A, there would only be one month remaining in the 24 month period to complete the comparison. In order to prevent the Planning Coordinator from having to perform concurrent comparison, I would suggest inserting a minimum along with the maximum time between events.
Individual
Joe O'Brien
NIPSCO
No
We think that for comparisons 24 months is too frequent; 5 years would be adequate.
Individual
Kathleen Goodman
ISO New England Inc.
No
The change does not clarify other aspects of this requirement. For example, this draft does not define “dynamic local event.” Also, the Purpose refers to “the interconncected transmission system” but R1 refers to “local event” so these differences should be clarified. Here are some suggested changes to this draft that might address these issues: Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of that portion of the interconnected transmission system for which the Planning Authority, Planning Coordinator, Reliabiltiy Coordinator, or Transmission Operator is responsible. Define “dynamic local event” as “dynamic local event as determined by the the Planning Authority, Planning Coordinator, Reliabiltiy Coordinator, or Transmission Operator”
Individual
Alice Ireland
Xcel Energy
Yes
Individual
Laurie Williams
PNM -Public Service Company of New Mexico
No

PNM appreciates the SDT's efforts to clarify R1.2 since the last version of the standard. As a registered PA/PC, PNM is still unclear on how to determine compliance with the requirement to perform an assessment every 24 months unless "no dynamic local event" occurs. The way the standard is worded appears to suggest that an entity could be compliant with the Standard as long as when a local event occurs, it is used to validate the models within 24 months of the event's occurrence. As an auditor, the last sentence in R1.2 seems to nullify, in the circumstance where no local event occurs, the requirement to perform at least one validation every 24 months. If the intent of the Standard is to only require a validation of dynamic local events within 24 months of their occurrence, PNM suggests removing the once every 24 month aspect of the requirement or alternatively, establishing a maximum amount of time that can occur between validations. For the latter, PNM submits the following modification to R1.2 for the SDT's consideration: 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 ...[delete text from original R1.2]... There shall be no more than [5?] calendar years between performance of validations performed pursuant to R1.2. PNM does not have a preference as to how frequently the validations must be performed, but sees a reliability need to ensure they are performed on some regular basis. The current R1.2 language may be too vague to ensure consistent enforcement among auditors and Regions. PNM agrees with the SDT's approach that 'dynamic local event' should not be a defined NERC term as defining this might put the Auditor in the position of having to somehow verify dynamic local events which would be burdensome without a corresponding improvement to BES reliability. However, it seems unlikely that a PA/PC would not experience an event at least once every 24 months given the brief guideline in the Standard which states, "a dynamic local event is a disturbance of the power system that produces some measureable transient response..."
Group
Arizona Public Service
Janet Smith
No
We propose the following redline to the standard in order to make the intent of the Standard clear. 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 (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs in the future, then perform a comparison within 24 months of that event.
Individual
Shirley Mayadewi
Manitoba Hydro

Yes
Although Manitoba Hydro is in general agreement with the standard, we have the following comments: (1) R1 – this part actually incorporates two actions 1) that the Planning Coordinator document a data validation process and 2) that the Planning Coordinator implement such documented process. As written, they are intertwined. (2) R1, 1.2 – punctuation is missing before the bracketed sentence. It might read better to delete the brackets and delete the word ‘Use’ and replace with ‘using’ to make the bracketed sentence part of the comparison requirement rather than a separate instruction. (3) R1, 1.4 – the words ‘the Planning Coordinator will use’ should be inserted after ‘Guidelines’. (4) M2 – notification should more appropriately be ‘a written request’ to be consistent with the requirement language. (5) Compliance 1.3 – a change was made to this language but it did not address our original concern. The language still refers specifically to a process found in the NERC Rules of Procedure. Manitoba Hydro has only adopted certain portions of the NERC Rules of Procedure. The typical language found in standards in this section (that just lists possible processes) is preferable for consistency with the other standards.
Group
Bonneville Power Administration
Andrea Jessup
Yes
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Group
FirstEnergy
Doug Hohlbaugh
Yes
FirstEnergy (FE) agrees that the change made by the SDT provides additional clarity as to when the validation required by the standard must be completed by the Planning Coordinator. FE’s Negative ballot position is based on our prior draft comments that remain concerns. Specifically, the standard is heavily dependent on the "documented data validation process" written by the PC. The standard is generally very vague and generic and provides very limited particulars and/or specifics. 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.

Group
SPP Standards Review Group
Shannon V. Mickens
Yes
We suggest deleting the phrase "…, and M1 through M2,…" as shown in the second paragraph of R1.2 in the Compliance Section. As written this sentence implies that the applicable entity must be compliant with the Measures of the Requirments. That is not the case. Applicable entities are required to demonstrate compliance with the Requirements. The Measures provide examples of what types of evidence can be used to show compliance with the requirements. In the second line in the second paragraph in the Rationale Box for R2, insert an "a" between "at" and "generator". In the first bullet at the bottom of Page 13 in the Guidelines and Technical Basis section, delete the "s" on "Voltages".
Individual
Don Idzior
Consumers Energy Company
No
MOD-33-1 is a standard that requires a data validation process. The measurement R1 does not provide enough guidance. Here are some quotes from R1 that start on page 13 of Model_ Validation_REDLINE_2013_1205.pdf that demonstrate what I mean "does not prescribe a specific method","entities are encouraged to perform the comparison on a more frequent basis", "the Planning Coordinator may consider among the other criteria", "may include simulations of". MOD-033-1 is too vague as written.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst has concerns over the new parenthetical language added to Requirement R1, Part 1.2 and requests the rationale for these additions. Specifically ReliabilityFirst has concerns with the 24 month periodicity in which a comparison needs to be completed. ReliabilityFirst believes the comparison should be completed as soon as possible (but not more than six months) following a dynamic local event. ReliabilityFirst also believes Requirement R1, Part 1.2 should be split up (thus creating a new Part 1.3) and deleting the last sentence regarding no dynamic local event occurring. With the description of the "dynamic local event" contained in the background portion of the standard, there should always be at least one event the Planning Coordinator may choose that may be validated within the two-year period. ReliabilityFirst offers the following for consideration: 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 (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison). 1.3 Comparison shall be completed within six calendar months of the dynamic local event.
Group
Duke energy
Michael Lowman
No
Duke Energy suggests revising the parenthetical in R1.2 to read as follows "(Use a dynamic local event that occurs 24 calendar month and complete that comparison within 24 calendar months of the dynamic local event)." This allows the PC the flexibility to choose which dynamic local event to use during the 24 month period if multiple dynamic local events occur in that 24 month period.
Group
Dominion
Connie Lowe
Yes
Group
JEA
Tom McElhinney
No
In support of our negative vote, we would like to maintain our comments from our last vote.
Individual
Eric Bakie
Idaho Power Company
Yes
Individual
Scott Langston
City of Tallahassee
Yes
Individual

Karen Webb
City of Tallahassee - Electric Utility
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)
Group
Florida Municipal Power Agency
Frank Gaffney
Our comments from the last posting were not addressed. Please see FMPA's comments posted on November 20, 2013.
Group
North American Generator Forum - Standards Review Team (NAGF-SRT)
Allen Schriver
Yes
Although the NAGF-SRT agrees with the clarification, the NAGF-SRT submits that the 24 month timeframe is too frequent and should be extended to 5 - 10 years.
Group
ACES Standards Collaborators
Ben Engelby
No
(1) Model validation is a good topic for a technical guideline document. We recommend that the drafting team consider other alternatives to developing a standard and work with the NERC Planning Committee to issue a guideline in lieu of a standard.The drafting team also concedes that "validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined." If this persists as a standard, we recommend that the drafting team provide some sort of threshold of disturbances and technical justification. There is too much ambiguity in the current language of the requirement. (2) For Requirement 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. We continue to ask the drafting team to provide a rationale. (3) The new parenthetical is R1, part 1.3 "(Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of

the dynamic local event)" is confusing. We recommend revising the language for clarity. (4) For Requirement R1, Part 1.3 needs to be modified to remove the clause "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 during an audit. (5) 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. Furthermore, we cannot fathom a situation in which an RC or TOP would refuse to provide data to their associated PC for the purposes of improving their modeling. This is particularly true given that almost all PCs are also registered as RCs and TOPs. Today the NERC registry shows there are 81 registered PCs. Of these 81, only 4 are not also registered as a TOP or RC. All four of these are part of a larger system in which models are developed primarily by larger. For example, three are located in Georgia and are part of the Georgia Integrated Transmission System that is jointly planned. The last remaining one is part of a joint action agency in Florida which is usually integrated into larger system. The bottom line is that this requirement is further obviated by the fact the PCs can get the necessary modeling information internally. We continue to request that the drafting team reference the P81 criteria and provide rationale why the requirement should remain in the standard. After our review of the criteria, we have determined that the requirement be struck in its entirety. (6) In regard to the statement by NERC Compliance in its guidance document, "Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training." What training will NERC compliance develop? Is this training for industry or auditors? Is this training the type of 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. (7) We request that a draft RSAW be developed and published with the standard. The compliance guidance is helpful, but does not provide enough details. We request additional guidance on how this standard will be audited. (8) Thank you for the opportunity to comment.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
The burden of this standard is well beyond what most might think it is.
Individual
Scott Brame
North Carolina Electric Membership Corporation
Yes

(1)Model validation is a good topic for a technical guideline document and we would have preferred that the drafting team consider other alternatives to developing a standard and work with the NERC Planning Committee to issue a guideline in lieu of a standard.The drafting team also concedes that “validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined.” We fully understand why the drafting team persists that this be a standard, but we still recommend that the drafting team provide some sort of threshold of disturbances and technical justification as in our opinion, there still remains much ambiguity in the current language of the requirement. (2)For Requirement 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. We continue to ask the drafting team to provide a rationale. (3)The new parenthetical is R1, part 1.3 “(Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event)” may be interpreted in various ways by PCs who are attempting to comply with this requirement. Can the drafting team consider providing a little more guidance to the PCs? (4)For Requirement R1, Part 1.3 needs to be modified to remove the clause “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 during an audit. (5)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. Furthermore, we cannot fathom a situation in which an RC or TOP would refuse to provide data to their associated PC for the purposes of improving their modeling. This is particularly true given that almost all PCs are also registered as RCs and TOPs. Today the NERC registry shows there are 81 registered PCs. Of these 81, only 4 are not also registered as a TOP or RC. All four of these are part of a larger system in which models are developed primarily by larger. For example, three are located in Georgia and are part of the Georgia Integrated Transmission System that is jointly planned. The last remaining one is part of a joint action agency in Florida which is usually integrated into larger system. The bottom line is that this requirement is further obviated by the fact the PCs can get the necessary modeling information internally. We continue to request that the drafting team reference the P81 criteria and provide rationale why the requirement should remain in the standard. After our review of the criteria, we have determined that the requirement be struck in its entirety. (6)In regard to the statement by NERC Compliance in its guidance document, “Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.” What training will NERC compliance develop? Is this training for industry or auditors? Is this training the type of 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. (7)We request that a draft RSAW be developed and published with the standard. The compliance guidance is helpful, but does not provide enough details. We request additional guidance on how this standard will be audited. (8)Thank you for the opportunity to comment.
Individual
Bill fowler
City of Tallahassee
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)
Group
ISO/RTO COuncil Standards Review Committee
Greg Campoli
Yes

Additional Comments:

Seminole Electric Cooperative, Inc.
Michael Haff

COMMENTS
The SDT allows entities to determine what amount of difference is “unacceptable” in Requirement R1 Part 1.3. If an entity does not believe that attempting to verify long-term planning models against actual system responses produces more accurate models, this Requirement appears to allow an entity to state an “unacceptable difference” that an entity may never experience, e.g., 1,000% difference between a model variable and an actual system response, if the entity truly believes that no amount of difference in unacceptable. Can the SDT comment on the scenario when entities choose very large differences due to the fact they do not believe low comparison differences are unacceptable?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2010-03 Modeling Data (MOD B)

The Project 2010-03 Drafting Team thanks all commenters who submitted comments on the draft MOD-033-1 standard. These standards were posted for a 45-day public comment period through January 21, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 32 sets of comments, including comments from approximately 106 different people from approximately 54 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - News England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.	Helen Lainis	Independent Electricity System Operator	NPCC	2
11.	Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Mark Kenny	Northeast Utilities	NPCC	1
15.	Christina Koncz	PSEG Power LLC	NPCC	5
16.	David Ramkalawan	Ontario Power Generatiuon, Inc,	NPCC	5
17.	Randy MacDondald	New Brunswick Power Transmission	NPCC	9
18.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
19.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
20.	Robert Pellegrini	The United Illuminating Company	NPCC	1
21.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
22.	Brian Robinson	Utility Services	NPCC	8
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
26.	Peter Yost	Consolidated Edison Co. of new York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Janet Smith	Arizona Public Service	X		X			X				

No Additional Responses

				1	2	3	4	5	6	7	8	9	10
3.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Karl Fraughton	Transmission Grid Modeling	WECC	1
2.	Dmitry Kosterev	Transmission Planning	WECC	1

				1	2	3	4	5	6	7	8	9	10
4.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	FE RBB - Segment 1	RFC	1
2.	Cindy Stewart	FE RBB - Segment 3	RFC	3
3.	Doug Hohlbaugh	FE RBB - Segment 4	RFC	4
4.	Ken Dresner	FE RBB - Segment 5	RFC	5
5.	Kevin Querry	FE RBB - Segment 6	RFC	6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

6. Brian Hallett	FE Transmission	RFC	1
7. Marissa McLean	FE Transmission	RFC	1
8. Ed Baznik	FE Transmission	RFC	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Nail	Independence Power and Light	SPP	3
2. Kevin Nincehelser	Westar	SPP	1, 3, 5, 6
3. Bo Jones	Westar	SPP	1, 3, 5, 6
4. Tiffany Lake	Westar	SPP	1, 3, 5, 6
5. Mo Awad	Westar	SPP	1, 3, 5, 6
6. Robert Rhodes	SPP	SPP	2

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Michael Lowman	Duke energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils		RFC	1
2. Lee Schuster		FRCC	3
3. Dale Goodwine		SERC	5
4. Greg Cecil		RFC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade		RFC	5, 6
2. Mike Garton		NPCC	5, 6
3. Randi Heise		MRO	5, 6
4. Michael Crowley		SERC	1, 3, 5, 6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Tom McElhinney	JEA	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson		FRCC	1
2. Garry Baker		FRCC	3
3. John Babik		FRCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Don Cuevas	Beaches Energy Services	FRCC	1
8.	Stan Rzad	Keys Energy Services	FRCC	1
9.	Mark Schultz	Green Cove Springs	FRCC	3

				1	2	3	4	5	6	7	8	9	10
10.	Group	Allen Schriver	North American Generator Forum - Standards Review Team (NAGF-SRT)					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	5
2.	Dana Showalter	E.ON Climate & Renewables	ERCOT	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
3.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
4.	Amber Skillern	East Kentucky Power Cooperative	SERC	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
12.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Marjorie Parsons		SERC	6
2.	Robbie Bottoms		SERC	1
3.	Tom Cain		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	DeWayne Scott		SERC	1
5.	Ian Grant		SERC	3
6.	David Thompson		SERC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Greg Campoli	ISO/RTO COuncil Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM	RFC	2
2.	Kathleen Goodman	ISO-NE	NPCC	2
3.	Ben Li	IESO	NPCC	2
4.	Terry Bilke	MISO	MRO	2
5.	Cheryl Moseley	ERCOT	ERCOT	2
6.	Charles Yeung	SPP	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Individual	David Jendras	Ameren	X		X		X	X				
15.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
16.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
17.	Individual	Scott Langston	City of Tallahassee	X									
18.	Individual	Bill fowler	City of Tallahassee			X							
19.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
20.	Individual	Lance Bean	Consumers Energy Company			X		X					
21.	Individual	Don Idzior	Consumers Energy Company			X	X	X					
22.	Individual	John	Falsey					X					
23.	Individual	Eric Bakie	Idaho Power Company	X									
24.	Individual	Michael Falvo	Independent Electricity System Operator		X								
25.	Individual	Kathleen Goodman	ISO New England Inc.		X								
26.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
27.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
28.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Scott Brame	North Carolina Electric Membership Corporation	X		X	X	X					
30.	Individual	Laurie Williams	PNM -Public Service Company of New Mexico	X		X							
31.	Individual	Anthony Jablonski	ReliabilityFirst										X
32.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: See summary consideration to Question 1, below.

Organization	Agree	Supporting Comments of "Entity Name"
N/A		

1. ***In draft 2 of proposed MOD-033-1 (Steady-State and Dynamic System Model Validation), Requirement R1, part 1.2, required "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." In response to comments, the SDT agreed that some might benefit from additional clarity of the SDT's intent in part 1.2. In response, the SDT confirms that the intent of the requirement is to complete comparison using a dynamic local event within 24 months of the last dynamic local event used in comparison and to complete each comparison within 24 months of the dynamic local event. The SDT has rephrased part 1.2 to clarify the intent of the requirement to ensure that it is clear that a PC will not face a timing scenario that makes it impossible to comply. Specifically, the SDT added language to clarify that the reference of "at least once every 24 calendar months" means that the PC must "use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event." This was the only change in the standard that may be substantive. Do you agree with the clarification? If not, please provide suggested alternative clarifications.***

Summary Consideration: The following is a summary consideration of the comments indicated below. Consistent with the NERC Standards Processes Manual, an individual response following each comment is not provided, and the team instead provides a summary response to each issue not previously considered and responded to from previous comment periods.

The 2010-03 Modeling Data Standard Drafting Team (SDT) thanks all participants for their feedback in finding ways to improve the proposed MOD-033-1 Reliability Standard. The SDT carefully considered all comments in determining whether to make changes to the standard, and this is a summary explanation of the SDT's deliberations. At this stage, the drafting team has reached a point where it has made a good faith effort at resolving applicable objections, and it has not made any substantive changes to MOD-033-1 since posting draft three. Therefore, the team is posting MOD-033-1 and its corresponding implementation plan for a final ballot.

In response to draft two, the SDT made one minor, but substantive, change to the language in Requirement R1, part 1.2, to address a specific timing concern that would have potentially and inadvertently created a situation where an entity would not have adequate time to perform its obligation under the requirement. The standard had otherwise achieved an approval rating that reflected industry consensus of more than two-thirds approval. In response to this change, some commenters agreed with the SDT that the change corrected the impossibility of collecting data and completing an analysis for a dynamic local event occurring in, for example, month 23 since the previous dynamic local event.

Some commenters provided comments that have already been considered and responded to during previous comment periods, and the SDT consideration and response to those issues remains the same. As noted above, the SDT believes that the majority of items

affecting consensus have been resolved, and the language in the standard reflects a consensus position. The suggestions for edits or changes already considered included topic areas such as, but not limited to, defining "dynamic local event," whether a standard is necessary, the scope of the standard, the timelines and details about Requirement R1 or Requirement R2, specific requirement language details, and that comparisons be conducted on less frequent intervals. One entity asserted that its comment from the last comment period relating to paragraph 81, duplication with other standards, the reliability need for validation, and suggesting a data request were not considered by the SDT. The SDT reviewed those previous comments and confirmed that those issues are discussed in summary response to the previous comment periods.

Rather than repeating those topics in this document, please refer to the response to comments from the previous two comment periods, which discusses each individual issue in detail. Both are posted on the Project 2010-03 SDT's project page. Draft one is located here:

http://www.nerc.com/pa/Stand/Project%20201003%20Modeling%20Data%20MOD%20B/Project_2010-03_Modeling_Data_Summary-of_Comments_2013-1007.pdf

And the response to comments from draft two is located here:

http://www.nerc.com/pa/Stand/Project%20201003%20Modeling%20Data%20MOD%20B/Project_2010-03_Modeling_Data_Summary-of_Comments_draft2_2013_1205.pdf

A few commenters asked for clarity or further changes regarding the 24 month timelines in Requirement R1 so that entities have flexibility to choose which dynamic local event they use, or that they are not forced to use a particular dynamic local event that occurs shortly after a previously used one. A few commenters indicated that the language may be confusing. Some commenters provided specific suggestions to change the language. The SDT did not make changes to the language, but explains that the requirement does provide such requested flexibility, as the parenthetical is read with the rest of part 1.2. Specifically, the dynamic local event chosen for comparison must be within 24 calendar months of the last chosen dynamic local event (but an entity may chose which one, so long as the 24 month time parameter is met, with other considerations for instances where the time between dynamic local events may exceed 24 calendar months), and once a dynamic local event is chosen for comparison, an entity must complete the comparison on that dynamic local event within 24 calendar months. On the issue of changing the wording of the parenthetical in part 1.2, the SDT notes that the language was heavily coordinated to reach a consensus point. The SDT appreciates the suggestions and has given them consideration. However, given the purpose of the requirement and the support reflected in the ballot for the current wording, changes to the language as suggested may not support the consensus position, and the SDT did not adopt them (with the exception of changing the capitalization of the word "use" to lowercase).

An entity provided suggested edits to the Compliance Section of the standard and suggested minor changes to specific words or phrases. The SDT notes that the Compliance Section language is similar to use in other standards under development, but also

confirms the commenter's understanding of the obligation under the requirements compared to the measures, and it did not make a change. However, the SDT is passing along this comment as a suggestion to ensure consistency in standards and projects under development. The other minor specific changes suggested by the entity concerned two minor typographical errors, and the SDT has made those corrections.

A commenter pointed out that the Purpose of MOD-033-1 refers to "the interconnected transmission system," but that Requirement R1 refers to "local event," and the entity asks for clarification of the differences. The SDT believes that when all Planning Coordinators in an Interconnection perform the comparisons required by the standard with local events, eventually, the model for the interconnected transmission system will be maintained with validated data.

One entity asked the SDT to comment on the scenario when entities choose very large differences as a threshold for "unacceptable" in Requirement R1 if the entity does not believe low comparison differences are unacceptable. The SDT notes that the requirement language specifies that entities must implement a process for data validation, which includes that comparisons occur within certain time parameters. As mentioned above, the SDT believes that by performing validations under the requirement, the model for the interconnected transmission system will be maintained with validated data, and those validations may help an entity determine instances of differences that are unacceptable to the entity. The SDT maintains that the Planning Coordinators are in the best position to determine when differences between expected performance and actual system behavior are unacceptable, and the requirement expects an entity to have guidelines it will use to make that determination. But the determination is one the Planning Coordinator must make. As the standard states in the "Guidelines and Technical Basis" section of the standard, "the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent."

Organization	Yes or No	Question 1 Comment
Arizona Public Service	No	We propose the following redline to the standard in order to make the intent of the Standard clear. 1.2. Comparison of the performance of the Planning Coordinator's portion of theexisting system in a planning dynamic model to actual system response, throughsimulation of a dynamic local event, at least once every 24 calendar months (Usea dynamic local event that occurs within 24 calendar months of the last dynamiclocal event used

Organization	Yes or No	Question 1 Comment
		in comparison and complete each comparison within 24calendar months of the dynamic local event). If no dynamic local event occurswithin the 24 calendar months, use the next dynamic local event that occurs in the future, then perform a comparison within 24 months of that event.
Response:		
Duke energy	No	Duke Energy suggests revising the parenthetical in R1.2 to read as follows"(Use a dynamic local event that occurs 24 calendar month and complete that comparison within 24 calendar months of the dynamic local event)."This allows the PC the flexibility to choose which dynamic local event to use during the 24 month period if multiple dynamic local events occur in that 24 month period.
Response:		
JEA	No	In support of our negative vote, we would like to maintain our comments from our last vote.
Response:		
ACES Standards Collaborators	No	(1) Model validation is a good topic for a technical guideline document. We recommend that the drafting team consider other alternatives to developing a standard and work with the NERC Planning Committee to issue a guideline in lieu of a standard.The drafting team also concedes that "validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined." If this persists as a standard, we recommend that the drafting team provide some sort of threshold of disturbances and technical justification. There is too much

Organization	Yes or No	Question 1 Comment
		ambiguity in the current language of the requirement.(2) For Requirement 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. We continue to ask the drafting team to provide a rationale.(3) The new parenthetical is R1, part 1.3 "(Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event)" is confusing. We recommend revising the language for clarity.(4) For Requirement R1, Part 1.3 needs to be modified to remove the clause "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 during an audit. (5) 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. Furthermore, we cannot fathom a situation in which an RC or TOP would refuse to provide data to their associated PC for the purposes of improving their modeling. This is particularly true given that almost all PCs are also registered as RCs and TOPs. Today the NERC registry shows there are 81 registered PCs. Of these 81, only 4 are not also registered as a TOP or RC. All four of these are part of a larger system in which models are developed primarily by larger. For example, three are located in Georgia and are part of the Georgia Integrated Transmission System that is jointly planned. The last remaining one is part of a joint action agency in Florida which is usually integrated into larger system. The bottom line is that this requirement is further obviated by the fact the PCs can get the necessary modeling information internally.

Organization	Yes or No	Question 1 Comment
		We continue to request that the drafting team reference the P81 criteria and provide rationale why the requirement should remain in the standard. After our review of the criteria, we have determined that the requirement be struck in its entirety. (6) In regard to the statement by NERC Compliance in its guidance document, “Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.” What training will NERC compliance develop? Is this training for industry or auditors? Is this training the type of 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.(7) We request that a draft RSAW be developed and published with the standard. The compliance guidance is helpful, but does not provide enough details. We request additional guidance on how this standard will be audited. (8) Thank you for the opportunity to comment.
Response:		
American Electric Power	No	After further review, AEP now believes that R2 is too open-ended in both data requested and potential format, especially given that only 30 days is being afforded to provide that data. MOD-032-1 added the text “unless a longer time period is agreed upon” to allow flexibility, and we believe similar verbiage should be added to MOD-033-1 as well. AEP disagrees with the response given by the team in its consideration of comments where it states that providing the data would not be unduly burdensome as it “only requires the TOP to provide any real time data that it has for a specific event or disturbance...”. As written, the requirement provide no bounds on what data could be requested, nor in what format. As a result, some requests could conceivably be quite burdensome and/or too difficult to provide within thirty days. The recommended text would provide the

Organization	Yes or No	Question 1 Comment
		flexibility necessary for both parties to agree on the amount of time needed to provide the data. In addition, AEP believes that performing comparisons every 24 months is unnecessarily excessive, and instead recommends the period be established as 60 months.Due to the concerns provided, and after further consideration, AEP has decided to vote negative on this proposed standard.
Response:		
City of Tallahassee	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)
Response:		
City of Tallahassee - Electric Utility	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)
Response:		
Consumers Energy Company	No	The measurement R1 does not provide enough guidance. Here are some quotes from R1 that demonstrate what I mean ‘does not prescribe a specific method or procedure for the validation’, ‘the outcome is left to the judgment of the Planning Coordinator’ , ‘entities are encouraged to perform

Organization	Yes or No	Question 1 Comment
		the comparison on a more frequent basis’, the Planning Coordinator may consider among the other criteria’ ‘ may include comparisons of'. In summary, MOD-0330-1 as written is too vague. For this reason, the Consumers Energy ballot body is voting negative on MOD-033-1.
Response:		
Consumers Energy Company	No	MOD-33-1 is a standard that requires a data validation process. The measurement R1 does not provide enough guidance. Here are some quotes from R1 that start on page 13 of Model_ Validation_REDLINE_2013_1205.pdf that demonstrate what I mean "does not prescribe a specific method","entities are encouraged to perform the comparison on a more frequent basis", "the Planning Coordinator may consider among the other criteria", "may include simulations of". MOD-033-1 is too vague as written.
Response:		
ISO New England Inc.	No	The change does not clarify other aspects of this requirement. For example, this draft does not define “dynamic local event.” Also, the Purpose refers to “the interconncected transmission system” but R1 refers to “local event” so these differences should be clarified. Here are some suggested changes to this draft that might address these issues:Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of that portion of the interconnected transmission system for which the Planning Authority, Planning Coordinator, Reliabiltiy Coordinator, or Transmission Operator is responsible.Define “dynamic local event” as “dynamic local event as determined by the the Planning Authority, Planning Coordinator, Reliabiltiy Coordinator, or Transmission Operator”

Organization	Yes or No	Question 1 Comment
Response:		
Kansas City Power & Light	No	Although I appreciate the drafting team's attempt at clarification of the standard, I believe that further modifications are necessary. First, I question why the clarification was inserted in parentheses and the placement of the clarification in general. Also, I have additional concerns regarding the following situation:Dynamic local event A occurs and the Planning Coordinator, according to R1.2, initiates the comparison of the model to actual system response. Dynamic local event B occurs the following month. There are no additional dynamic local events in the following 23 months. In this situation, the comparisons would have to be almost concurrent, forcing the Planning Coordinator to do twice as many comparison as otherwise required. Also, if the Planning Coordinator decided to wait to see if another event occurred within the 24 month period after event A, there would only be one month remaining in the 24 month period to complete the comparison.In order to prevent the Planning Coordinator from having to perform concurrent comparison, I would suggest inserting a minimum along with the maximum time between events.
Response:		
NIPSCO	No	We think that for comparisons 24 months is too frequent; 5 years would be adequate.
Response:		
PNM -Public Service Company of New Mexico	No	PNM appreciates the SDT's efforts to clarify R1.2 since the last version of the standard. As a registered PA/PC, PNM is still unclear on how to determine compliance with the requirement to perform an assessment every 24 months unless "no dynamic local event" occurs. The way the standard is worded appears to suggest that an entity could be compliant

Organization	Yes or No	Question 1 Comment
		with the Standard as long as when a local event occurs, it is used to validate the models within 24 months of the event's occurrence. As an auditor, the last sentence in R1.2 seems to nullify, in the circumstance where no local event occurs, the requirement to perform at least one validation every 24 months. If the intent of the Standard is to only require a validation of dynamic local events within 24 months of their occurrence, PNM suggests removing the once every 24 month aspect of the requirement or alternatively, establishing a maximum amount of time that can occur between validations. For the latter, PNM submits the following modification to R1.2 for the SDT's consideration: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 ...[delete text from original R1.2]... There shall be no more than [5?] calendar years between performance of validations performed pursuant to R1.2.PNM does not have a preference as to how frequently the validations must be performed, but sees a reliability need to ensure they are performed on some regular basis. The current R1.2 language may be too vague to ensure consistent enforcement among auditors and Regions. PNM agrees with the SDT's approach that 'dynamic local event' should not be a defined NERC term as defining this might put the Auditor in the position of having to somehow verify dynamic local events which would be burdensome without a corresponding improvement to BES reliability. However, it seems unlikely that a PA/PC would not experience an event at least once every 24 months given the brief guideline in the Standard which states, "a dynamic local event is a disturbance of the power system that produces some measureable transient response..."
Response:		

Organization	Yes or No	Question 1 Comment
ReliabilityFirst	No	ReliabilityFirst has concerns over the new parenthetical language added to Requirement R1, Part 1.2 and requests the rationale for these additions. Specifically ReliabilityFirst has concerns with the 24 month periodicity in which a comparison needs to be completed. ReliabilityFirst believes the comparison should be completed as soon as possible (but not more than six months) following a dynamic local event. ReliabilityFirst also believes Requirement R1, Part 1.2 should be split up (thus creating a new Part 1.3) and deleting the last sentence regarding no dynamic local event occurring. With the description of the "dynamic local event" contained in the background portion of the standard, there should always be at least one event the Planning Coordinator may choose that may be validated within the two-year period. ReliabilityFirst offers the following for consideration: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 (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison). 1.3 Comparison shall be completed within six calendar months of the dynamic local event.
Response:		
FirstEnergy	Yes	FirstEnergy (FE) agrees that the change made by the SDT provides additional clarity as to when the validation required by the standard must be completed by the Planning Coordinator. FE's Negative ballot position is based on our prior draft comments that remain concerns. Specifically, the standard is heavily dependent on the "documented data validation process" written by the PC. The standard is generally very vague and generic and provides very limited particulars and/or specifics. We support the validation effort, however, it should be limited to near-term (year one)

Organization	Yes or No	Question 1 Comment
		models since longer term models may differ greatly in modeling assumptions such as load, generation dispatch and interchange flows.
Response:		
SPP Standards Review Group	Yes	We suggest deleting the phrase "..., and M1 through M2,..." as shown in the second paragraph of R1.2 in the Compliance Section. As written this sentence implies that the applicable entity must be compliant with the Measures of the Requirments. That is not the case. Applicable entities are required to demonstrate compliance with the Requirements. The Measures provide examples of what types of evidence can be used to show compliance with the requirements. In the second line in the second paragraph in the Rationale Box for R2, insert an "a" between "at" and "generator". In the first bullet at the bottom of Page 13 in the Guidelines and Technical Basis section, delete the "s" on "Voltages".
Response:		
North American Generator Forum - Standards Review Team (NAGF-SRT)	Yes	Although the NAGF-SRT agrees with the clarification, the NAGF-SRT submits that the 24 month timeframe is too frequent and should be extended to 5 - 10 years.
Response:		
Tennessee Valley Authority	Yes	The burden of this standard is well beyond what most might think it is.
Response:		
Ameren	Yes	We believe that this clarification should address concerns regarding the impossibility of collecting data and completing an analysis for a dynamic local event occurring in month 23 since the previous dynamic local event.

Organization	Yes or No	Question 1 Comment
Response:		
Manitoba Hydro	Yes	Although Manitoba Hydro is in general agreement with the standard, we have the following comments:(1) R1 - this part actually incorporates two actions 1) that the Planning Coordinator document a data validation process and 2) that the Planning Coordinator implement such documented process. As written, they are intertwined. (2) R1, 1.2 - punctuation is missing before the bracketed sentence. It might read better to delete the brackets and delete the word 'Use' and replace with 'using' to make the bracketed sentence part of the comparison requirement rather than a separate instruction. (3) R1, 1.4 - the words 'the Planning Coordinator will use' should be inserted after 'Guidelines'. (4) M2 - notification should more appropriately be 'a written request' to be consistent with the requirement language. (5) Compliance 1.3 - a change was made to this language but it did not address our original concern. The language still refers specifically to a process found in the NERC Rules of Procedure. Manitoba Hydro has only adopted certain portions of the NERC Rules of Procedure. The typical language found in standards in this section (that just lists possible processes) is preferable for consistency with the other standards.
Response:		
North Carolina Electric Membership Corporation	Yes	(1)Model validation is a good topic for a technical guideline document and we would have preferred that the drafting team consider other alternatives to developing a standard and work with the NERC Planning Committee to issue a guideline in lieu of a standard.The drafting team also concedes that "validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined." We fully understand

Organization	Yes or No	Question 1 Comment
		why the drafting team persists that this be a standard, but we still recommend that the drafting team provide some sort of threshold of disturbances and technical justification as in our opinion, there still remains much ambiguity in the current language of the requirement.(2)For Requirement 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. We continue to ask the drafting team to provide a rationale.(3)The new parenthetical is R1, part 1.3 "(Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event)" may be interpreted in various ways by PCs who are attempting to comply with this requirement. Can the drafting team consider providing a little more guidance to the PCs? (4)For Requirement R1, Part 1.3 needs to be modified to remove the clause "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 during an audit. (5)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. Furthermore, we cannot fathom a situation in which an RC or TOP would refuse to provide data to their associated PC for the purposes of improving their modeling. This is particularly true given that almost all PCs are also registered as RCs and TOPs. Today the NERC registry shows there are 81 registered PCs. Of these 81, only 4 are not also registered as a TOP or RC. All four of these are part of a larger system in which models are developed primarily by larger. For example, three are

Organization	Yes or No	Question 1 Comment
		located in Georgia and are part of the Georgia Integrated Transmission System that is jointly planned. The last remaining one is part of a joint action agency in Florida which is usually integrated into larger system. The bottom line is that this requirement is further obviated by the fact the PCs can get the necessary modeling information internally. We continue to request that the drafting team reference the P81 criteria and provide rationale why the requirement should remain in the standard. After our review of the criteria, we have determined that the requirement be struck in its entirety. (6)In regard to the statement by NERC Compliance in its guidance document, “Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.” What training will NERC compliance develop? Is this training for industry or auditors? Is this training the type of 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.(7)We request that a draft RSAW be developed and published with the standard. The compliance guidance is helpful, but does not provide enough details. We request additional guidance on how this standard will be audited. (8)Thank you for the opportunity to comment.
Response:		
Bonneville Power Administration	Yes	
Dominion	Yes	
ISO/RTO COuncil Standards Review Committee	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
City of Tallahassee	Yes	
Falsey	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Florida Municipal Power Agency		Our comments from the last posting were not addressed. Please see FMPA's comments posted on November 20, 2013.
Response:		

Additional Comments:

Seminole Electric Cooperative, Inc.
Michael Haff

COMMENTS

The SDT allows entities to determine what amount of difference is "unacceptable" in Requirement R1 Part 1.3. If an entity does not believe that attempting to verify long-term planning models against actual system responses produces more accurate models, this Requirement appears to allow an entity to state an "unacceptable difference" that an entity may never experience, e.g., 1,000% difference between a model variable and an actual system response, if the entity truly believes that no amount of difference in unacceptable. Can the SDT comment on the scenario when entities choose very large differences due to the fact they do not believe low comparison differences are unacceptable?

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).
4. Third posting for a 10-day final ballot (December 2013).

Description of Current Draft

This is the first posting of this standard for a 10-day final ballot. This standard was previously posted for a 45-day formal comment period and ballot in July 2013 and October 2013. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-033-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
Final ballot	December 2013
BOT adoption	February 2014

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-1**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. **Functional Entities:**

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:
http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf.

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.

(Rationale continued on next page)

Rationale for R1: Continued

These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.

Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Rationale for R3: In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the “ERO or its designee” supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, “industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*” (Emphasis added).

This requirement is about the Planning Coordinator’s obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the “designee” for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

“Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

			steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 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* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. 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 entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. 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).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).
4. ~~3.~~4. Third posting for a 10-day final ballot (December 2013).

Description of Current Draft

This is the ~~second~~ ~~third~~first posting of this standard for a ~~45~~10-day ~~formal comment period and~~final ballot. This standard was previously posted for a 45-day formal comment period and ballot in July 2013 and October 2013. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-033-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
Final ballot	December 2013
BOT adoption	~~December 2013~~February 2014

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-1**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)

   This proposed standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives ~~(to include several remaining directives~~ from FERC Order No. 693~~)~~, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the ~~that~~ SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard ~~be applicable~~apply to Planning Coordinators. The inclusion of ~~the~~ Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf.

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.

(Rationale continued on next page)

Rationale for R1: Continued

These suggested improvements ~~in the proposed approach~~ are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.

Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.~~; and~~

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Rationale for R3: In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of ~~the request~~receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement ~~R3~~ R2 in support of their respective Interconnection-wide case(s). While different entities in each ~~of the three~~ Interconnection~~s~~ create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The ~~Applicable Entity~~applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an ~~Applicable Entity~~applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to ~~Section 3.0 of Appendix 4C of~~ the NERC Rules of Procedure for ~~the~~ a list of ~~Compliance Monitoring and Assessment~~compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% ~~or~~ but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% ~~or~~ but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner (s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner (s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state,	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and

			dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR

			requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written

			response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required	The Planning Coordinator made available the required	The Planning Coordinator made available the required	The Planning Coordinator made available the required

			data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	data to the ERO or its designee but failed to provide greater than 25% ~~or~~ but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	data to the ERO or its designee but failed to provide greater than 50% ~~or~~ but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

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[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A~~n~~ Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided ~~to the GO~~ by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 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* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**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)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, ~~I~~if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. 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 entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. 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).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

October 7, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards
MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirement R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements

MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Consideration of Issues and Directives

Project 2010-03 – Modeling Data (MOD B)

October 7, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R3 provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by Project 2012-05 ATC Revisions (MOD A).

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific “at a minimum” data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as	FERC Order No. 693	See the response to Paragraph 1155.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	See the response to Paragraph 1148.
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission planner to provide fault and disturbance lists.		
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" This is being addressed by MOD-032, Requirement R3, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement R1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be	FERC Order No. 693	See response to paragraph 1210.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
validated against actual system responses.		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-012-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-013-1, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	Translation to New Standard or Other Action	Description and Change Justification
NEW	MOD-032-1, R3	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, it provides a mechanism to obtain more accurate information and data in cases where the initial data provided may have technical or accuracy concerns, and it meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" In those cases, additional detail regarding the data may be necessary.
NEW	MOD-032-1, R4	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective Interconnection-wide case(s).
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-032-1 and MOD-033-1
October 22, 2013

Introduction

The NERC Compliance department (Compliance) worked with the 2010-03 Modeling Data standard drafting team (SDT) to review the proposed standards MOD-032-1 and MOD-033-1. The purpose of the review was to discuss the requirements of the pro forma standards to obtain an understanding of their intended purposes and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the SDT in order to aid the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions should both assist the SDT in further refining the standard and serve as a tool to develop auditor training.

MOD-032-1 and MOD-033-1 Questions

Question 1

Under MOD-032-1 Requirement R1, how will the requirement for "(e)ach Planning Coordinator and each of its Transmissions Planners *shall jointly develop* . . . data requirements and reporting procedures . . ." be assessed for compliance? (Emphasis added).

Compliance Response to Question 1

During a compliance assessment, an auditor will look for evidence that the entities jointly developed the requirements and reporting procedures as required. In the absence of evidence demonstrating joint development, an auditor will not entertain arguments that one entity was cooperative and the other was not. Both entities will be assessed based on whether there was joint development. The auditor will note the results to be included in the next compliance assessment of the entity that was not currently being audited.

Evidence of joint development may include emails, drafts of data requirement documents or reporting procedures, meeting notes, phone records, or other evidence or attestations demonstrating agreement for the data requirements and reporting procedures.

Question 2

Under MOD-032-1 Requirement R2, will the auditor verify only that the data was delivered as specified, or will the auditor make a determination regarding whether the quality of the data is sufficient?

Compliance Response to Question 2
Based on the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified. This standard does not specify the criteria around quality, so auditors will not make any assessments in that regard.

Question 3
In MOD-033-1 Requirement R1, Part 1.3, is it clear what is meant by “unacceptable differencences in performance”?

Compliance Response to Question 3
Based on the language in the requirement and the purpose of the standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guidelines for how the Planning Coordinator will determine when and under what circumstances the performance comparisons conducted under Parts 1.1 and 1.2 result in “unacceptable differences.”

Conclusion
Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the versions of the proposed standards requirements referenced in this document.

Attachment A

MOD-032-1 Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing data to the Planning Coordinator.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R3, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request; or a statement by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider that it has not received written notification regarding technical concerns with the data submitted.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R3 when requested by the ERO or its designee.

MOD-033-1 Requirements and Measures

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;

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;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

DRAFT Reliability Standard Audit Worksheet[1]

MOD-032-1 – Data for Power System Modeling and Analysis

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X[3]							X	
R2	X		X			X				X		X			X
R3	X		X			X				X		X			X
R4							X[3]								

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" whiles the registration criteria lists "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include:

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Provide the modeling data requirements and reporting procedures that were developed. Provide evidence the data requirements and reporting procedures were jointly developed between the applicable Planning Coordinator and Transmission Planners which could consist of emails, meeting minutes, or the inclusion of the names of the jointly collaborating entities in any written procedures.

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-032-1, R1
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence and verify procedures cover items listed in parts 1.1 through 1.3 for the Planning Coordinator's planning area.
Note to Auditor: Auditor will seek evidence that the specific data reporting requirements of each of the items in Attachment 1 are included in the developed data requirements and reporting procedures. Auditor will seek evidence that the entity jointly developed the requirements and reporting procedures as required. Entities will be assessed based on whether there was joint development. Joint agreement on data requirements and reporting procedures constitutes joint development. Evidence regarding the participation, or lack thereof, of an entity not under audit may be used as evidence of compliance at the time of such other entity's audit or other formal compliance monitoring process.	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence such as noted in M2.
Provide evidence that the data submitted meets the parameters of the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-032-1, R2
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Determine if entity's data submissions match the requirements developed by its Planning Coordinator and

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	Transmission Planner. Based on auditor judgment, a sampling of data submissions may be used as opposed to the auditor examining the entire population of data submissions.
Note to Auditor: This standard does not specify criteria around quality of data, so auditors are not to make any assessments in that regard. Auditor will seek evidence that the data submitted meets the parameters of the data requirements and reporting procedures developed by its Planning Coordinator , including a sampling of steady state, dynamics and short circuit data as specified in Attachment 1. The auditor may also contact the applicable Planning Coordinator(s) or Transmission Planner(s) for additional confirmation that required modeling data was submitted according the developed procedures.	

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows:

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request, or a statement that it has not received written notification regarding technical concerns with the data submitted.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[6]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M3.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-032-1, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R3) Review evidence provided to determine if any notifications were received by entity.
	(part 3.1) Review evidence to verify entity responded by updating data or providing an explanation with a technical basis for maintaining the current data.
	(part 3.2) Review evidence to determine if entity responded, per part 3.1, within 90 calendar days as outlined in the requirement.
Note to Auditor: Based on the auditor's judgment, he or she may inquire with entity's Planning Coordinator or Transmission Planner regarding whether any such notifications were made or simply confirm with the entity under audit.	

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Auditor Notes:

R4 Supporting Evidence and Documentation

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.

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to MOD-032-1, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review evidence provided to determine if entity made models available to the ERO or its designee in accordance with the requirement.
Note to Auditor: Auditor should verify with personnel within the ERO, or its designee, regarding its requests made of the entity to support creation of the Interconnection-wide case(s). If ERO personnel inform that entity provided required information, then no further testing of this requirement is necessary.	

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC compliance, Standards	New Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2010-03 - Modeling Data

VRF and VSL Justifications

The following table provides analysis and justification for each VRF and VSL assigned in MOD-032-1 and MOD-033-1.

VRF and VSL Justifications – MOD-032-1, Requirement R1	
Proposed VRF	**LOWER**
NERC VRF Discussion	The purpose of this requirement is to ensure that the data requirements and reporting procedures established by planning coordinators meet minimum criteria. It is a requirement in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the bulk electric system.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for creation of data requirements and reporting procedures to support data used in Interconnection-wide power flow and dynamics cases. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Lower VRF is consistent with the risk impact of a violation.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement maps from MOD-011-0 and MOD-013-0, which were not approved by FERC, which has a VRF of High for the main requirement and Medium for the requirement parts. Requirement R1 acts in concert with its corollary requirement, Requirement R2, which requires data owners to submit the required data, which has a VRF of Medium, and together the VRFs are consistent with previous versions.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.

FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R2	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	The purpose of this requirement is to ensure that data owners subject to the standard submit data according to the data requirements and reporting procedures established by Planning Coordinators under Requirement R1. Not providing the data could directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for submission of data according to data requirements and reporting procedures to support Interconnection-wide power flow and dynamics cases. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Medium VRF is consistent with the risk impact of a violation, especially in light of the blackout recommendations.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement maps from MOD-010 and MOD-012, which have VRFs of Medium; therefore, the VRF is consistent with previous versions.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than

less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit

			modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R3	
Proposed VRF	**LOWER**
NERC VRF Discussion	This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. As a feedback loop for increasing accuracy of data, violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system, and a Lower VRF is appropriate.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement provides a feedback loop for certain circumstances, and the VRF is only applied at the requirement level and the Requirement Parts are treated equally. The assigned VRF is consistent with the risk impact of a violation across the standard.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This is a new requirement and is commensurate in risk with Requirement R1. Both requirements have the same VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	Coordinator or Transmission Planner).		

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R4	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). Information for use in the planning models is important, and a violation of this requirement could affect reliability, but a violation would not likely lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Requirement R4 specifies actions to ensure that data provided under the standard is available for use in the Interconnection-wide case(s), and, much like the importance of entities providing the data under Requirement R2, a VRF of Medium is appropriate.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces MOD-014 and MOD-015, and a Medium VRF is consistent with those standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-033-1, Requirement R1	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	This requirement requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response. Accuracy of data used in the planning models may be affected. A violation of this requirement could affect reliability, but a violation would not likely lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement specifies that Planning Coordinators must implement a data validation process. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Medium VRF is consistent with the risk impact of a violation.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: N/A. There are no other NERC Reliability Standards that address similar reliability goals
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar months (or the next dynamic local event in cases where there is more than 24 months between events).

did perform the simulation within 28 calendar months.	did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	than or equal to 36 calendar months.	

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-033-1, Requirement R2			
Proposed VRF	**LOWER**		
NERC VRF Discussion	The purpose of this requirement is to ensure that actual system behavior data is available for Planning Coordinators for use in validation under Requirement R1. The information is in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the bulk electric system.		
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.		
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for certain entities to provide certain data to Planning Coordinators in support of the validations required of the Planning Coordinators under Requirement R1. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Lower VRF is consistent with the risk impact of a violation.		
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: N/A. There are no other NERC Reliability Standards that address similar reliability goals		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not

provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days; OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1 and MOD-033-1

Final Ballot for MOD-032-1: December 6-16, 2013
Comment Period for MOD-033-1: December 6, 2013 – January 21, 2014

Upcoming:
Additional Ballot and Non-Binding Poll for MOD-033-1: January 10-21, 2014

Now Available

A final ballot for **MOD-032-1** is open through **8 p.m. Eastern on Monday, December 16, 2013.** A 45-day formal comment period for **MOD-033-1** is open through **8 p.m. Eastern on Tuesday, January 21, 2014.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **MOD-033-1** is open through **8 p.m. Eastern on Tuesday, January 21, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An additional ballot for **MOD-033-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as previously outlined.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or by telephone at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-032-1

Final Ballot Results

Now Available

A final ballot for **MOD-032-1** concluded at **8 p.m. Eastern on Monday, December 16, 2013.**

The standard achieved a quorum and received sufficient votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Quorum /Approval
87.53% / 77.49%

Background information for this project, can be found on the project page.

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with appropriate regulatory authorities.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

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-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2010-03 MOD-032-1 (MOD B)
Ballot Period:	12/6/2013 - 12/16/2013
Ballot Type:	**Final Ballot**
Total # Votes:	330
Total Ballot Pool:	377
Quorum:	**87.53 % The Quorum has been reached**
Weighted Segment Vote:	77.49 %
Ballot Results:	**The standard has passed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	104	1	67	0.761	21	0.239	0	7	9
2 - Segment 2	9	0.8	7	0.7	1	0.1	0	0	1
3 - Segment 3	80	1	50	0.746	17	0.254	0	3	10
4 - Segment 4	29	1	13	0.591	9	0.409	0	0	7
5 - Segment 5	90	1	54	0.783	15	0.217	0	7	14
6 - Segment 6	50	1	31	0.721	12	0.279	0	2	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	8	0.7	6	0.6	1	0.1	0	1	0
Totals	**377**	**7.1**	**234**	**5.502**	**76**	**1.598**	**0**	**20**	**47**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Negative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John Chin	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	

1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	

2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS-FirstEnergy
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C Esquerre	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	

3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	COMMENT RECEIVED - Joe O'Brien NIPSCO
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Abstain	
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Abstain	
5	Dairyland Power Coop.	Tommy Drea	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus	Abstain	
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		

6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).
4. Third posting for a 45-day comment period and concurrent ballot (December 2013).
5. Fourth posting for a 10-day final ballot (January 2014).

Description of Current Draft

This is the third posting of this standard for a 45-day formal comment period and ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-032-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
Additional 45-day Formal Comment Period with Parallel Ballot	December 2013
Final ballot	January 2014
BOT adoption	February 2014

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**
2. **Number: MOD-033-1**
3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their

Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

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;

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 (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a “month 23” dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SAR and supporting package posted for comment (July 2013).
2. First posting for 45-day comment period and concurrent ballot (July 2013).
3. Second posting for a 45-day comment period and concurrent ballot (October 2013).
4. Third posting for a 45-day comment period and concurrent ballot (December 2013).
5. ~~4.~~ Fourth posting for a 10-day final ballot (January 2014).

Description of Current Draft

This is the third posting of this standard for a 45-day formal comment period and ballot. Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015. This standard and Standard MOD-032-1 address the outstanding directives while simultaneously incorporating recommendations for improvement from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS).

Anticipated Actions	Anticipated Date
Post SAR	July 2013
45-day Formal Comment Period with Parallel Ballot	July 2013
Additional 45-day Formal Comment Period with Parallel Ballot	October 2013
Additional 45-day Formal Comment Period with Parallel Ballot	December 2013
Final ballot	January 2014
BOT adoption	February 2014

Version History

Version	Date	Action	Change Tracking
1	TBD	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.	

Definitions of Terms Used in Standard

None

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**

2. **Number: MOD-033-1**

3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")

This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

4.1.2 Reliability Coordinator

4.1.3 Transmission Operator

5. **Effective Date:**

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their

Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

Rationale for R1:

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." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

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;

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 (~~Use~~ use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- ~~Voltages~~ Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of "at least once every 24 calendar months" is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a "month 23" dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event's occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event's occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Project 2010-03 (MOD-032-1 and MOD-033-1)

October 7, 2013

Approvals Requested
MOD-032 -1 – Data for Power System Modeling and Analysis
MOD-033-1 – Steady-State and Dynamic System Model Validation

Prerequisite Approvals
None

Effective Date

New or Revised Standards
MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental 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. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standards for Retirement

MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 – Midnight of the day immediately prior to the Effective Date of MOD-032-1, Requirement R2, in the particular Jurisdiction in which the new standard is becoming effective.

Initial Performance of Periodic Requirements

MOD-033-1, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the Effective Date of MOD-033-1.

Consideration of Issues and Directives

Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 290. The Commission directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date. This means that the models should be updated and benchmarked to actual events. We find that this requirement is essential in order to have an accurate simulation of the performance of the grid and from which to comparably calculate ATC, therefore increasing transparency and decreasing the potential for undue discrimination by transmission providers.	FERC Order No. 890	The concept that models should be updated and benchmarked, through periodic review and modification, are fully covered by both new standards addressing modeling data MOD-032-1 and model validation MOD-033-1. MOD-032-1 thoroughly addresses modeling data submission and review, along with providing a mechanism to update data that may have technical issues. MOD-033-1 addresses validation of models to ensure that expected system behavior acceptably matches actual system response. Additionally, MOD-032-1, Requirement R1 covers item (2) short circuit data and item (3) transient and dynamic stability simulation data by requiring those items as part of the data requirements, and MOD-032-1, Requirement R3 provides a feedback loop for issues of data from the data owners. The portion of the directive related to contingency, subsystem, and monitoring files were addressed by MOD-001-1a, Requirement R9, and further consideration, if any, is being addressed by Project 2012-05 ATC Revisions (MOD A).

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Para 1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.	FERC Order No. 693	For operations, the sharing of contingencies is covered by MOD-001-1a, and for planning, TPL-001-4 requires lists of Contingencies be compiled in Requirements R3 and R4 as part of the required planning assessments in that standard. Those planning assessments must be distributed to adjacent PCs and TPs, and to any other functional entity with a reliability need, addressing the directives' focus related to access to information by planners in paragraphs 1148, 1154, 1178, and 1183.
Para 1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.		
Para 1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.	FERC Order No. 693	The Planning Authority plays an integral role in the standard modifications, both receiving data from the respective data owners, submitting data for its planning area to support the interconnection models, and validating models relative to their planning areas. The referenced attachment 1 specifies the specific “at a minimum” data for steady-state, dynamics, and short circuit data, establishing a level of consistency of data to support larger-scale, interconnection-specific models. However, the standard also recognizes that operational disparities may exist across North America, providing sufficient flexibility for Planning Coordinators to specify format and cases most appropriate to their specific circumstances and interconnection.
Para 1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as	FERC Order No. 693	See the response to Paragraph 1155.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.		
Para 1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.	FERC Order No. 693	See the response to Paragraph 1148.
Para 1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the	FERC Order No. 693	See the response to Paragraph 1148.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission planner to provide fault and disturbance lists.		
Para 1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.	FERC Order No. 693	See response to paragraph 1155.
Para 1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the	FERC Order No. 693	This paragraph was clarified in FERC Order 693-A, paragraph 131, which stated “that ‘[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,’” but acknowledges “that, in certain circumstances, actual data may not be initially available and only obtained through ‘verification of the dynamic models with actual disturbance data.’” This is being addressed by MOD-032, Requirement R3, which provides a mechanism to obtain more accurate information and data in cases where the initial data provided has technical or accuracy concerns. Furthermore, MOD-033-1 requires comparison of actual disturbance data to verify accuracy of dynamics models.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.		
Para 1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	FERC Order No. 693	See response to paragraph 1155
Para 1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report and developing models for the Eastern Interconnection.	FERC Order No. 693	Standard MOD-033-1 addresses this directive, adding a validation process requirement for PCs aimed specifically at ensuring models are validated against actual system responses. Model validation for individual generators and/or power plants is already required by Reliability Standards MOD-025-2, MOD-026-1, and MOD-027-1.
Para 1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be	FERC Order No. 693	Similar to the consideration of paragraph 1210, Standard MOD-033-1, Requirement R1 addresses this directive, adding a validation process requirement for PCs that requires validation through simulation to ensure that the maximum discrepancy between actual system performance and the model do not

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require 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.		exceed the point where decisions made by the Planning Coordinator based on output from the model would be inconsistent with actual system response. In addition, the drafting team determined not to specify numeric accuracy thresholds in the standard itself. For instance, specifying percent for accuracy purposes is potentially problematic, as it may unintentionally exaggerate the degree of mismatch (e.g., 10 MW v. 20 MW (100% error) on a 345 KV line is not generally significant).
Para 1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be	FERC Order No. 693	See response to paragraph 1210.

Project 2010-03 - Modeling Data		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
validated against actual system responses.		

Project 2010-03 – Modeling Data (MOD B)
October 7, 2013

Mapping Document Showing Translation of MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 to MOD-032-1 and MOD-033-1.

Standard: MOD-010-0 – Steady-State Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-010-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-010-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.

Standard: MOD-011-0 – Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-011-0 R2	MOD-032-1, R1 and R2	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-011-0, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-012-0 R1	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners
MOD-012-0 R2	MOD-032-1, R2	Changed to require submission of the data to Planning Coordinators and Transmission Planners

Standard: MOD-013-1 – Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-013-1 R1	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements.
MOD-013-1 R2	MOD-032-1, R1	Changed to require Planning Coordinators with each of its Transmission Planners to jointly develop the data requirements and reporting procedures for their planning areas instead of requiring RROs to develop such requirements and procedures for their respective interconnections. Rather than specify the required components in the requirement parts, MOD-032-1 leverages an attachment to detail each of the steady-state, dynamics, and short circuit data requirements. MOD-032-1, Requirement R1, Part 1.3's inclusion of specifications for distribution maps to the portion of MOD-013-1, Requirement R2 to "make the data requirements and reporting procedures available on request."

Standard: MOD-014-0 – Development of Steady-State System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-014-0 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.
MOD-014-0 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R1	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

Standard: MOD-015-0.1 – Development of Dynamics System Models		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
MOD-015-0.1 R2	Deleted	The modeling data standard focuses on clarifying data submission requirements to support building the interconnection models and creates a framework in MOD-032-1, Requirement R4 to support Planning Coordinators making available the models reflecting data received from its data owners for use in building their respective Interconnection-wide case(s). The RRO functionality is not in the NERC functional model, and, as such, requiring them to coordinate to build an Interconnection-wide case is no longer necessary.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-032-1, R3	This requirement provides a feedback loop to support clarifying or correcting data that a Planning Coordinator or Transmission Planner identifies as having possible technical concerns. Furthermore, it provides a mechanism to obtain more accurate information and data in cases where the initial data provided may have technical or accuracy concerns, and it meets the directive under FERC Order 693, paragraph 1197, as clarified by FERC Order 693-A, paragraph 131, which stated "that '[a]chieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data,'" but acknowledges "that, in certain circumstances, actual data may not be initially available and only obtained through 'verification of the dynamic models with actual disturbance data.'" In those cases, additional detail regarding the data may be necessary.
NEW	MOD-032-1, R4	This is a new requirement that supports creation of a framework for submission of the data by Planning Coordinators for use in building their respective Interconnection-wide case(s).
NEW	MOD-033-1, R1	This is a new standard that addresses validation, and it also meets several directives from FERC Order Nos. 890 and 693 regarding the validation of models to ensure that expected system behavior acceptably matches actual system response.

New Requirements not found in existing MOD standards		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
NEW	MOD-033-1, R1	The Planning Coordinator will need actual real time system data in order to perform the validations required in MOD-033-1, Requirement R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator or Transmission Operator to supply real time data, if it has the data, to any requesting Planning Coordinator.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-032-1 and MOD-033-1
October 22, 2013

Introduction

The NERC Compliance department (Compliance) worked with the 2010-03 Modeling Data standard drafting team (SDT) to review the proposed standards MOD-032-1 and MOD-033-1. The purpose of the review was to discuss the requirements of the pro forma standards to obtain an understanding of their intended purposes and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the SDT in order to aid the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions should both assist the SDT in further refining the standard and serve as a tool to develop auditor training.

MOD-032-1 and MOD-033-1 Questions

Question 1

Under MOD-032-1 Requirement R1, how will the requirement for "(e)ach Planning Coordinator and each of its Transmissions Planners *shall jointly develop* . . . data requirements and reporting procedures . . ." be assessed for compliance? (Emphasis added).

Compliance Response to Question 1

During a compliance assessment, an auditor will look for evidence that the entities jointly developed the requirements and reporting procedures as required. In the absence of evidence demonstrating joint development, an auditor will not entertain arguments that one entity was cooperative and the other was not. Both entities will be assessed based on whether there was joint development. The auditor will note the results to be included in the next compliance assessment of the entity that was not currently being audited.

Evidence of joint development may include emails, drafts of data requirement documents or reporting procedures, meeting notes, phone records, or other evidence or attestations demonstrating agreement for the data requirements and reporting procedures.

Question 2

Under MOD-032-1 Requirement R2, will the auditor verify only that the data was delivered as specified, or will the auditor make a determination regarding whether the quality of the data is sufficient?

Compliance Response to Question 2

Based on the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified. This standard does not specify the criteria around quality, so auditors will not make any assessments in that regard.

Question 3

In MOD-033-1 Requirement R1, Part 1.3, is it clear what is meant by "unacceptable differencences in performance"?

Compliance Response to Question 3

Based on the language in the requirement and the purpose of the standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guidelines for how the Planning Coordinator will determine when and under what circumstances the performance comparisons conducted under Parts 1.1 and 1.2 result in "unacceptable differences."

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the versions of the proposed standards requirements referenced in this document.

Attachment A

MOD-032-1 Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1; and

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those responsible for providing data to the Planning Coordinator.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R3, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of the request; or a statement by the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider that it has not received written notification regarding technical concerns with the data submitted.

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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R3 when requested by the ERO or its designee.

MOD-033-1 Requirements and Measures

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;

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;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator 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]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

DRAFT Reliability Standard Audit Worksheet[1]

MOD-033-1 – Stead-State and Dynamic System Model Validation

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1							X[3]								
R2									X				X		

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" whiles the registration criteria lists "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes:

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;

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. (Use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R1) Documented data validation process that addresses Parts 1.1 through 1.4.
(Part 1.1) Comparisons of performance as outlined in Part 1.1 as requested by auditor.
(Part 1.2) Comparisons of performance as outlined in Part 1.2 as requested by auditor.
(Part 1.3) Evidence of analysis summarizing results of comparisons outlined in Parts 1.1 and 1.2 against established guidelines.
(Part 1.3) Evidence of implementation of actions to resolve differences in performance identified under Part 1.3 summarizing actions taken.

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, R1
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Verify existence of a documented data validation process addressing parts 1.1 through 1.4.
	(Part 1.1) Review documented data validation process to verify it includes a provision for comparison of the existing system to actual system behavior per the requirements of Part 1.1 at least once every 24 calendar months. Review the entity's comparison(s) to determine that it was executed in accordance with its data validation process document and that it occurred at least once every 24 months.
	(Part 1.2) Review documented data validation process to verify it includes a provision for dynamic comparison of the existing system to actual system behavior per the requirements of Part 1.2 at least once during the timeframe established in Part 1.2. Review the entity's comparison(s) to determine that it was executed in accordance with its data validation process and that it occurred within the timeframe established in Part 1.2.
	(Part 1.3) Review documented data validation process to verify it includes guidelines to determine unacceptable differences in performance under Part 1.1 or 1.2. Review entity's analyses to gain reasonable assurance that it was executed as described in its data validation process document.
	(Part 1.4) Review documented data validation process to verify it includes guidelines to resolve differences in performance identified under Part 1.3. Also, review the analyses outlined in Part 1.3 to ascertain whether differences in performance identified resulted in actions being taken to address the differences.

Note to Auditor: Based on the language in the requirement and the purpose of the Standard, which is to implement a process to validate data, the auditor will verify that the documented process includes guideline discussions about how the entity will determine when, and under what circumstances, the performance comparisons conducted under Parts 1.1 and 1.2 result in "unacceptable differences." Under part 1.3, an auditor will not assess the quality of the entity's guideline of what constitutes an "unacceptable difference," just that the validation process has been implemented and followed. Auditors will verify that any

differences identified under part 1.3 were resolved per the entity's guidelines. 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.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator 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.

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator who has indicated a need for the data for validation purposes within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and reply) to determine if entity responded to information request(s) as required in Requirement R2 within 30 days of receiving a written request from any Planning Coordinator.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Planning Coordinators to determine if requests for data were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	10/31/2013	NERC Compliance, Standards	New Document
2	1/8/2013	NERC Compliance, Standards	Changed language of Requirement 1 Part 1.2 to match new version of the Reliability Standard.

Project 2010-03 - Modeling Data

VRF and VSL Justifications

The following table provides analysis and justification for each VRF and VSL assigned in MOD-032-1 and MOD-033-1.

VRF and VSL Justifications – MOD-032-1, Requirement R1	
Proposed VRF	**LOWER**
NERC VRF Discussion	The purpose of this requirement is to ensure that the data requirements and reporting procedures established by planning coordinators meet minimum criteria. It is a requirement in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the bulk electric system.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for creation of data requirements and reporting procedures to support data used in Interconnection-wide power flow and dynamics cases. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Lower VRF is consistent with the risk impact of a violation.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement maps from MOD-011-0 and MOD-013-0, which were not approved by FERC, which has a VRF of High for the main requirement and Medium for the requirement parts. Requirement R1 acts in concert with its corollary requirement, Requirement R2, which requires data owners to submit the required data, which has a VRF of Medium, and together the VRFs are consistent with previous versions.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.

FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R2	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	The purpose of this requirement is to ensure that data owners subject to the standard submit data according to the data requirements and reporting procedures established by Planning Coordinators under Requirement R1. Not providing the data could directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for submission of data according to data requirements and reporting procedures to support Interconnection-wide power flow and dynamics cases. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Medium VRF is consistent with the risk impact of a violation, especially in light of the blackout recommendations.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement maps from MOD-010 and MOD-012, which have VRFs of Medium; therefore, the VRF is consistent with previous versions.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than

less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit

			modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R3	
Proposed VRF	**LOWER**
NERC VRF Discussion	This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. As a feedback loop for increasing accuracy of data, violation of this requirement would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system, and a Lower VRF is appropriate.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement provides a feedback loop for certain circumstances, and the VRF is only applied at the requirement level and the Requirement Parts are treated equally. The assigned VRF is consistent with the risk impact of a violation across the standard.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This is a new requirement and is commensurate in risk with Requirement R1. Both requirements have the same VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	Coordinator or Transmission Planner).		

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-032-1, Requirement R4	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). Information for use in the planning models is important, and a violation of this requirement could affect reliability, but a violation would not likely lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Requirement R4 specifies actions to ensure that data provided under the standard is available for use in the Interconnection-wide case(s), and, much like the importance of entities providing the data under Requirement R2, a VRF of Medium is appropriate.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces MOD-014 and MOD-015, and a Medium VRF is consistent with those standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-033-1, Requirement R1	
Proposed VRF	**MEDIUM**
NERC VRF Discussion	This requirement requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response. Accuracy of data used in the planning models may be affected. A violation of this requirement could affect reliability, but a violation would not likely lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement specifies that Planning Coordinators must implement a data validation process. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Medium VRF is consistent with the risk impact of a violation.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: N/A. There are no other NERC Reliability Standards that address similar reliability goals
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement may affect the bulk power system, but is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar months (or the next dynamic local event in cases where there is more than 24 months between events).

did perform the simulation within 28 calendar months.	did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	than or equal to 36 calendar months.	

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

VRF and VSL Justifications – MOD-033-1, Requirement R2			
Proposed VRF	**LOWER**		
NERC VRF Discussion	The purpose of this requirement is to ensure that actual system behavior data is available for Planning Coordinators for use in validation under Requirement R1. The information is in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions, be expected to adversely affect the electrical state or capability of the bulk electric system.		
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: Requirement supports recommendation 14: Improve system modeling data and data exchange practices.		
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement calls for certain entities to provide certain data to Planning Coordinators in support of the validations required of the Planning Coordinators under Requirement R1. The VRF is only applied at the requirement level and the Requirement Parts are treated equally. A Lower VRF is consistent with the risk impact of a violation.		
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: N/A. There are no other NERC Reliability Standards that address similar reliability goals		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Violation of this requirement itself is unlikely to adversely affect the bulk power system.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: The proposed requirement does not co-mingle more than one obligation and therefore has a single VRF.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not	The Reliability Coordinator or Transmission Operator did not

provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days; OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs provide reasonable gradations of severity, and they do not lower current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: N/A Guideline 2b: The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	N/A
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	N/A

Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-033-1

A Final Ballot is now open through February 5, 2014

Now Available

A final ballot for **MOD-033-1 – Stead-State and Dynamic System Model Validation** is open through **8 p.m. Eastern on Wednesday, February 5, 2014.**

Background information for this project can be found on the project page.

Instructions

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-03 Modeling Data (MOD B)
MOD-033-1

Final Ballot Results

Now Available

A final ballot for **MOD-033-1 – Steady-State and Dynamic System Model Validation** concluded at **8 p.m. Eastern on Wednesday, February 5, 2014.**

The standard achieved a quorum and received sufficient votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results
Quorum: 82.49%
Approval: 82.45%

Background information for this project, can be found on the project page.

Next Steps
The NERC Board of Trustees adopted the standard on February 6, 2014. The standard will be filed with applicable regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-03 MOD-033-1 (MOD B)
Ballot Period:	1/27/2014 - 2/5/2014
Ballot Type:	**Final Ballot**
Total # Votes:	311
Total Ballot Pool:	377
Quorum:	**82.49 % The Quorum has been reached**
Weighted Segment Vote:	82.45 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	104	1	66	0.835	13	0.165	0	9	16
2 - Segment 2	9	0.8	7	0.7	1	0.1	0	0	1
3 - Segment 3	80	1	50	0.833	10	0.167	0	7	13
4 - Segment 4	29	1	12	0.706	5	0.294	0	5	7
5 - Segment 5	90	1	47	0.81	11	0.19	0	11	21
6 - Segment 6	50	1	33	0.805	8	0.195	0	4	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	3	0.1	1	0.1	0	0	0	1	1

10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**377**	**6.9**	**225**	**5.689**	**49**	**1.211**	**0**	**37**	**66**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY

				COMMENTS
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Mid-Continent Area Power Pool	Larry E. Brusseau		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Abstain	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	COMMENT RECEIVED
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	

2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	COMMENT RECEIVED
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	

3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
				SUPPORTS THIRD

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	PARTY COMMENTS
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY

				COMMENTS
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair		
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD

				PARTY COMMENTS
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit H

Standard Drafting Team Roster

Project 2010-03 MOD B Drafting Team Roster

Name and Title	Company and Address	Contact Info	Bio
Bobby Jones, Chair Planning Manager, Stability and Special Studies	Southern Company Services 600 North 18th street Birmingham, AL 35203	205-257-6148 rajones@southernco.com	Mr. Jones is currently the Planning Manager for Stability and Special Studies in the Transmission Planning Department at Southern Company Services. He has been managing this area for Southern for the past 19 years. In this role, he performs and oversees angular stability, voltage stability, UFLS, UVLS, and other studies. He also is responsible for the dynamics modeling data for Southern. Earlier in his career, Mr. Jones was involved in transient voltage analysis, harmonics studies, power quality, and surge protection. He has a total of 40 years experience in the industry working for the Southern Company. Mr. Jones served as a member of the NERC ATFNSDT Standard Drafting Team (TPL Standard), chairman of the SERC UFLS Standard Drafting Team, and chair of the NERC Project 2010-03 (MOD B) Standard Drafting Team. Mr. Jones obtained a BSEE degree from the University of Alabama in 1973 and an MSEE degree from University of Alabama – Birmingham in 1978. He is a registered Professional Engineer in Alabama.
Reené Miranda, Vice Chair Senior Planning Engineer	Xcel Energy, Inc 600 South Tyler St Amarillo, TX, 79101	(806) 378-2136 rene.miranda@xcelenergy.com	Mr. Miranda is a Senior Transmission Planning Engineer with Southwestern Public Service Company (SPS), an Xcel Energy Company, and has 19 years of experience in the electric utility industry. He has worked as a staff engineer in distribution design and served as a Team-Lead in power system distribution. His present position, among other things, includes performing both near-term and long-term planning studies, which include the NERC TPL assessment studies. He also serves as a Subject Matter Expert during NERC audits for the SPS control area. Mr. Miranda is responsible for the model building effort of the Southwestern Public Service Company transmission system, which include both steady state and dynamics stability models. He is an active participant and voting member of the Southwest Power Pool (SPP) Model Development Working Group (MDWG), participating in the development of modeling procedures as wells as serving on several task forces within the SPP. Mr. Miranda received both a Master of Science and Bachelor of Science degree in Electrical Engineering from New Mexico State University in 1995 and 1992, respectively and is a member of the Panhandle Section of the Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society.

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Kent Bolton Staff Engineer – Planning Services	Western Electricity Coordinating Council 155 N 400 W Salt Lake City, UT 84103	(801) 883-6842 kent@wecc.biz	Mr. Bolton has fifteen years of experience working for the Western Electricity Coordinating Council (WECC) in the Planning Services department. Responsibilities have included compilation of WECC base cases, preparation of the Annual Study Report, assistance with various reports related to WECC work group and subcommittee activities and participation on the associated groups. Mr. Bolton currently is a member of the WECC Modeling and Validation Work Group, the Under-Frequency Load Shedding Review Group and the NERC System Analysis and Modeling Subcommittee. Mr. Bolton received a Bachelor of Science degree in Electrical Engineering – Power Option from Brigham Young University in Provo, UT in 1992 and a Master of Engineering degree in Electrical Engineering - Electric Power Systems from the University of Idaho in Moscow, ID in 2010. Mr. Bolton is a registered Professional Engineer in the State of Utah.
Jeff Gindling Principle Engineer Transmission Planning	Duke Energy 139 East Fourth Street Cincinnati, OH 45202	513-287-3479 Jeff.gindling@duke-energy.com	Mr. Gindling has 25 years of experience in the power industry. He has been at Duke Energy's Transmission Planning group for 18 years. In his current role he is the Duke Energy Midwest lead for transmission interconnected generation projects, Subject Matter Expert (SME) for Transmission Planning Standards and various transmission system studies and assessments. Mr. Gindling has extensive experience in Transmission System Planning and Operation, modeling, simulations in both steady–state and stability analysis, Project Management, Process Improvement, Regulatory Filings, Compliance, FERC/NERC standards and policies. Mr. Gindling received a Bachelor of Science in Electrical Engineering Technology degree from Northern Kentucky University, Highland Heights, Kentucky in 1995 and is a registered Professional Engineer in the State of Ohio.

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Wayne Haidle, P.E. Senior Engineer	Basin Electric Power Cooperative 1717 East Interstate Avenue Bismarck, ND 58503-0564	701-557-5643 WHaidle@bepc.com	Mr. Haidle has over 38 years of direct involvement with the electric power industry. Experience includes distribution and transmission substation design, construction supervision, system protection ranging from design to settings, model development and studies encompassing steady state, short circuit, and dynamics, SCADA and EMS systems with emphasis on advanced applications including breaker oriented models with state estimation, dispatcher power flow, and forecasting. He also performed studies for generator interconnection and transmission service. Mr. Haidle graduated with a BSEE major from Montana State University and is registered as a professional engineer in the state of North Dakota. While employed at Montana-Dakota Utilities Co. for 31 years he also served in various technical capacities with the Midcontinent Area Power Pool (MAPP), Midwest Reliability Organization (MRO), and Midwest (Midcontinent) Independent System Operator (MISO). Additionally, Mr. Haidle has provided instruction and course development for the Bismarck State College online energy technology program and subsequent adjunct support. While employed at Basin Electric Power Cooperative (BEPC) for the last 6 years, Mr. Haidle has served as subject matter expert in varying capacities related to NERC compliance while directly engaged in model development and support of BEPC and member systems in a multi-state area in the eastern interconnection involving the MRO and its Model Building Subcommittee in particular. Model development furthermore has included ongoing integration with MISO and increasing involvement with the Southwest Power Pool (SPP).

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Durgésh Manjuré Manager, System Modeling	Midcontinent Independent System Operator, Inc. (MISO) 2985 Ames Crossing Road, Eagan, MN 55121	651.632.8410 dmanjure@misoenergy.org	Mr. Manjuré has over 12 years of experience in the power industry. He has a strong background in reliability and economic transmission planning including system expansion, generator interconnection, transmission service and production cost analysis. In his current role as Manager, System Modeling at MISO, he is focused on developing and implementing processes for building and validating transmission system models to support MISO's Planning function. He is actively involved in the industry and serves on groups such as the NERC System Analysis and Modeling Subcommittee, IEEE Wind and Solar Power Coordinating Committee and as Chair of the EPRI Grid Planning Task force. Mr. Manjuré has published over 20 peer-reviewed technical articles in IEEE and other reputed journals and conferences. He is a Senior Member of the IEEE and holds Doctorate, Master's and Bachelor's degrees in Electrical Engineering.
Jay Teixeira, P.E. Manager, Model Administration	Electric Reliability Council of Texas 2705 West Lake Drive Taylor, TX, 76574	512-248-6582 Jay.Teixeira@ercot.com	Mr. Teixeira has 24 years of electric power industry experience. He has been at ERCOT for 17 years. In his current position, Mr. Teixeira manages the group that builds and maintains the ERCOT Network Operations model that is used in the Energy Management System, Market Management System, Congestion Revenue Rights, and System Planning. Other responsibilities at ERCOT prior to his current position include Transmission Planning, SCADA, and ICCP. Prior to his work at ERCOT, Mr. Teixeira worked for over 6 years in the Transmission Planning section of City Public Service in San Antonio, Texas. Prior to that, Mr. Teixeira served 6 years in the United States Air Force as a Radar Navigator/Navigator on a B-52 bomber. Mr. Teixeira graduated with a BSEE from the North Carolina A&T State University in Greensboro, North Carolina in 1983. He is a registered Professional Engineer in the State of Texas.

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Catherine Wesley Senior Analyst	PJM Interconnection 2750 Monroe Blvd Audubon, PA 19403	610-666-4628 catheirine.wesley@pjm.com	Ms. Wesley is a Senior Analyst with the NERC & Regional Coordination department for PJM Interconnection. PJM administers one of the largest energy markets and operates North America's largest centrally dispatched electricity grid. In her current position, Ms. Wesley participates in compliance activities specific to coordinating the reliable operation of the PJM Interconnection in accordance with the NERC and Regional Reliability Standards, and NAESB Business Practices. She also provides technical and business support and guidance to PJM departments and member companies in addressing reliability and business practice standards compliance. Prior to joining PJM, Ms. Wesley was employed by Exelon Corporation for 19 years in various roles, including project manager and outage supervisor. Ms. Wesley has participated in several industry committees including the North American Energy Standards Board Wholesale Electric Quadrant (WEQ), the ISO/RTO Council's Standards Review Committee, the North American Electric Reliability Corporation (NERC) Standards Committee's Process Subcommittee and the Reliability*First* Standards Committee.
Eric Allen, NERC Staff Senior Engineer, Reliability Initiatives and System Analysis	North American Electric Reliability Corporation (NERC) 3353 Peachtree Road NE, Suite 600—North Tower Atlanta, GA 30326	404-446-9612 eric.allen@nerc.net	Mr. Allen received his B.S. degree in Electrical Engineering from Worcester Polytechnic Institute in 1993 and his S.M. degree in Electrical Engineering from the Massachusetts Institute of Technology in 1995. In 1998 he received the Ph.D. degree in Electrical Engineering from M.I.T. with the thesis titled "Stochastic Unit Commitment in a Deregulated Electric Utility Industry." Mr. Allen was employed for more than 7 years as a Senior Engineer in transmission planning at the New York ISO, and he is now employed as a Senior Engineer in Reliability Initiatives and System Analysis at the North American Electric Reliability Council (NERC). He participated extensively in the investigation of the August 14, 2003 blackout. He is a licensed Professional Engineer in New York and participates in the Power System Dynamic Performance and Power System Relaying Committees of IEEE, and is currently Vice-chair of PSRC H Subcommittee.

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Steven Noess, NERC Staff Associate Director of Standards Development, Standards	North American Electric Reliability Corporation (NERC) 3353 Peachtree Road NE, Suite 600—North Tower Atlanta, GA 30326	404-217-9691 steven.noess@nerc.net	Mr. Noess is associate director of standards development at the North American Electric Reliability Corporation (NERC) in Atlanta, GA, and has been employed by NERC since 2011. Prior to joining NERC, Mr. Noess was an attorney at the Minnesota Legislature. Before becoming an attorney, he was an officer in the United States Army. Mr. Noess has a bachelor's of science degree from the U.S. Military Academy, West Point, NY, and a law degree from the University of Minnesota Law School.