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 STANDARD MOD-031-1 AND RETIREMENT OF RELIABILITY STANDARDS MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 AND MOD-021-1

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard MOD-031-1 – Demand and Energy Data. NERC requests that the Commission approve proposed Reliability Standard MOD-031-1 (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 E), (iii) the proposed NERC Glossary definitions for the terms Demand Side Management ("DSM") and Total Internal Demand, and (iv) the retirement of currently effective Reliability Standards MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1 (the "Existing MOD C Standards"), as detailed in this Petition.

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[1] 16 U.S.C. § 824o (2006).

[2] 18 C.F.R. § 39.5 (2014).

[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*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

As required by Section 39.5(a)[5] of the Commission's regulations, this Petition presents the technical basis and purpose of proposed Reliability Standard MOD-031-1, a summary of the development history (Exhibit F) and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (Exhibit C). The NERC Board of Trustees approved proposed Reliability Standard MOD-031-1, the associated Implementation Plan and the new and modified NERC Glossary terms on May 7, 2014.

I. EXECUTIVE SUMMARY

Proposed Reliability Standard MOD-031-1 is designed to replace, consolidate and improve upon the Existing MOD C Standards in addressing the collection and aggregation of Demand and energy data necessary to support reliability assessments performed by the ERO and Bulk-Power System planners and operators.[7] The reliability of the Bulk-Power System is dependent on having an adequate amount of resources and transmission infrastructure available to serve peak Demand while also maintaining a sufficient margin to address operating events. Accordingly, it is vital for entities and the ERO, consistent with its statutory obligation,[8] to perform reliability studies to assess resource and transmission adequacy, and identify the need for any Bulk-Power System reinforcements (e.g., new generation plants or transmission lines) to help ensure the continued

5 18 C.F.R. § 39.5(a) (2013).

6 *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).

7 Currently effective Reliability Standard MOD-020-0 also relates to the collection of Demand and energy data, specifically, the provision of interruptible Demand and direct control load management data to System Operators and Reliability Coordinators. Because Reliability Standard MOD-020-0 applies to the operational time frame, as opposed to the planning horizon to which the Existing MOD C Standards apply, the proposed Reliability Standard does not address the issues currently covered by Reliability Standard MOD-020-0 nor is Reliability Standard MOD-020-0 proposed for retirement. However, the proposed Reliability Standard addresses the outstanding Commission directive related to MOD-020-0, as discussed below.

8 FPA Section 215(g) requires the ERO to conduct periodic assessments of the reliability and adequacy of the Bulk-Power System in North America. 16 U.S.C. § 824o(g) (2006).

reliable operation of the Bulk-Power System. The purpose of the proposed Reliability Standard is to provide applicable entities the authority to establish comprehensive data requirements and reporting procedures for the collection of actual and forecast Demand and energy (i.e., Demand, Net Energy for Load and Demand Side Management) data necessary to support the development of reliability assessments.

As explained below, the framework established in proposed MOD-031-1 provides planners and operators of the Bulk-Power System access to actual and forecast Demand and energy data, as well as other related information, needed to perform resource adequacy studies. The proposed Reliability Standard also supports the continued development of the reliability assessments prepared by the ERO. NERC has the responsibility under Section 215 of the FPA to prepare assessments of the overall reliability and adequacy of the North American Bulk-Power System.[9] NERC prepares seasonal and long-term assessments to examine the current and future reliability, adequacy and security of the North American Bulk-Power System in accordance with Section 800 of its Rules of Procedure. NERC's reliability assessments identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the Bulk-Power System to meet future Demand. These assessments inform industry, policy makers, and governmental authorities of Bulk-Power System reliability needs and guide their decisions for the electric industry.

Proposed MOD-031-1 was developed to address Commission directives from Order No. 693[10] to modify the Existing MOD C Standards. Consistent with those directives, proposed MOD-

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[9] 16 U.S.C. § 824o(g); 18 C.F.R. § 39.11.

[10] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222 (2007), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

031-1 improves upon the Existing MOD C Standard by: (1) streamlining the Reliability Standards to clarify data collection requirements; (2) including Transmission Planners as applicable entities that must report Demand and energy data; (3) requiring applicable entities to report weather-normalized annual peak hour actual Demand data from the previous year to allow for meaningful comparison with forecasted values; and (4) requiring applicable entities to provide an explanation of, among other things: (i) how their Demand Side Management forecasts compare to actual Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.; and (ii) how their peak Demand forecasts compare to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted. Consistent with FERC's directives, NERC is also proposing to revise the definition of Demand-Side Management to include activities or programs undertaken by *any applicable entity*, not just a Load Serving Entity or its customers, to achieve a reduction in Demand.

Proposed Reliability Standard MOD-031-1 consists of four requirements that collectively help to ensure that the necessary Demand and energy data is available to those entities that perform reliability assessments, as follows:

- *Requirement R1* mandates that each Planning Coordinator[11] or Balancing Authority[12] that identifies a need for the collection of Demand and energy data shall develop and issue a data request for such data from relevant entities in its area. The requirement mandates that the data request clearly identify: (i) the entities responsible for providing the data; (ii) the data to be provided by each entity; and (iii) the schedule for providing the data. Requirement R1 also specifies the type of Demand and energy data that may be requested.

- *Requirement R2* obligates the entities identified in a data request issued pursuant to Requirement R1 to provide the requested data to their Planning Coordinator or Balancing Authority, as applicable, pursuant to the format and schedule specified in the data request.

- *Requirement R3* requires that the Planning Coordinator or the Balancing Authority, as applicable, provide the data collected under Requirement R2 to their Regional Entity, if requested, to facilitate the ERO's development of reliability assessments.

- *Requirement R4* requires entities to share their Demand and energy data with any Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner that demonstrates a reliability need for such data, subject to applicable confidentiality, regulatory or security restrictions. The requirement to share such data helps ensure that planners and operators of the Bulk-Power System have access to complete and accurate data necessary to conduct their own resource adequacy assessments.

By providing for consistent documentation and information sharing practices for the collection and aggregation of Demand and energy data, proposed Reliability Standard MOD-031-1 promotes efficient planning practices and supports the identification of needed system reinforcements. Furthermore, the requirement in the proposed Reliability Standard to report actual Demand, Net Energy for Load and Demand-Side Management data from the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. These activities ultimately enhance the reliability of the Bulk Electric System.

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11 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 Standard lists both Planning Coordinators and Planning Authorities to avoid confusion as to which registered entities are subject to the proposed Reliability Standard. As explained in Applicability Section 4.1.1, however, the requirements of the proposed Reliability Standard only use the term "Planning Coordinator."

12 As explained further below, Planning Coordinators are the entities that collect and aggregate the Demand and energy data in certain regions while in other regions Balancing Authorities serve that function. The proposed Reliability Standard does not change those practices.

For the reasons discussed herein, NERC respectfully requests that the Commission approve the proposed Reliability Standard and the new and modified NERC Glossary terms 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:[13]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[14] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[15] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United

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13 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 regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

14 16 U.S.C. § 824o (2006).

15 *Id.* § 824(b)(1).

States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[16] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[17] of the Commission's regulations requires the ERO to file for Commission 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[18] and Section 39.5(c)[19] 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.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[20] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[21] In its ERO

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16 *Id.* § 824o(d)(5).

17 18 C.F.R. § 39.5(a) (2012).

18 16 U.S.C. § 824o(d)(2).

19 18 C.F.R. § 39.5(c)(1).

20 *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).

21 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.

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. The Existing MOD C Standards

The Existing MOD C Standards are designed to help ensure that historical and forecasted Demand and energy data is available for past event validation and future system assessment. In particular, the Existing MOD C Standards, along with Reliability Standard MOD-020-0, require the collection of actual and forecast Demand data necessary to analyze the resource needs to serve peak Demand while maintaining a sufficient margin to address operating events, as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements. Specifically, it requires the Planning Authority and the Regional Reliability Organization (now referred to as the Regional Entity) to have documentation identifying the scope and details of the actual and forecast Demand and load data, and controllable DSM data to be reported for system modeling and reliability analysis.

- MOD-017-0.1 provides for the data requirements for actual and forecast peak Demand and Net Energy for Load. It requires Load Serving Entities, Planning Authorities, and Resource Planners to annually provide aggregated information on: (1) integrated hourly Demands; (2) actual monthly and annual peak Demand (MW) and net load energy (GWh) for the prior year; (3) monthly peak Demand forecasts and net load energy for the next two years and (4) annual peak demand forecasts (summer and winter) and annual net load energy for at least five and up to ten years into the future.

- MOD-018-0 requires Load Serving Entities, Planning Authorities, Transmission Planners and Resource Planners to submit load data reports that: (1) indicate whether the Demand data includes the Regional Reliability Organization's non-members' Demands and (2) addresses how assumptions, methods and uncertainties are treated.

- MOD-019-0.1 provides for the collection of Interruptible Demand and Direct Control Load Management. It requires that Load Serving Entities, Planning Authorities, Transmission Planners, and Resource Planners annually provide their forecasts of interruptible Demands and Direct Control Load Management to NERC, the Regional Reliability Organization and other entities as specified in the documentation required by MOD-016-1.1.

- MOD-020-0 addresses the need to provide Interruptible Demand and Direct Control Load Management Data to System Operators and Reliability Coordinators. It requires that each Load Serving Entity, Planning Authority, Transmission Planner, and Resource Planner identify its amount of: (1) interruptible Demand and (2) Direct Control Load Management to Transmission Operators, Balancing Authorities and Reliability Coordinators upon request.

- MOD-021-1 requires Load Serving Entities, Transmission Planners, and Resource Planners to clearly document how they address the Demand and energy effects of DSM programs. The standard also requires an applicable entity to include information detailing how DSM measures are addressed in the forecasts of its peak demand and annual Net Energy for Load in the data reporting procedures required by MOD-016-0.

In Order No. 693, the Commission approved Reliability Standards MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, MOD-020-0, and MOD-021-1 but directed NERC to make, or consider, the following modifications:

- Modify MOD-016-1 and MOD-017-0 to "expand the applicability section to include the Transmission Planner, on the basis that under the NERC Functional Model the Transmission Planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans."[22]

- Modify MOD-017-0 to require "reporting of temperature and humidity [data] along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values."[23] In responding to this directive, FERC stated that the Commission should address how to treat entities whose load does not vary with temperature and humidity.[24]

- Modify MOD-017-0 "to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations."[25]

[22] Order No. 693 at PP 1232, 1255.

[23] *Id*. at P 1249.

[24] *Id*. at P 1250.

[25] *Id*. at P 1251.

- Modify MOD-017-0 "to add a requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias."[26]

- Consider whether to modify MOD-017-0 to allow some exceptions to the requirement to provide hourly Demand data.[27]

- Consider whether to modify MOD-018-0 to exclude small entities from complying with the standard.[28]

- Modify MOD-019-0 "to require reporting of the accuracy, error and bias of controllable load forecasts."[29]

- Modify MOD-019-0 to add a new requirement "that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon."[30]

- Modify MOD-020-0 "to require reporting of the accuracy, error and bias of controllable load forecasts."[31]

- Modify MOD-021-0 by adding a requirement for the standardization of principles on reporting and validating DSM program information.[32]

- Modify the definition of the term "Demand Side Management" to add to the definition "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use.[33]

D. Procedural History of Proposed Reliability Standard MOD-031-1

The proposed Reliability Standard was developed as part of NERC Project 2010-04 Demand Data (MOD C), which was formally initiated on July 18, 2013 with the posting of a Standard Authorization Request along with a draft of proposed Reliability Standard MOD-031-1

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26 *Id*. at P 1252.

27 Order No. 693 at P 1256.

28 *Id*. at P 1265.

29 *Id*. at P 1276

30 *Id*. at P 1277.

31 *Id*. at P 1287.

32 *Id.* at P 1298.

33 *Id*. at P 1232.

for a 45-day comment period and ballot. The project arose from an informal development process that NERC initiated in February 2013 to address the outstanding Commission directives from Order No. 693 related to Existing MOD C Standards. 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, both in person and in conference calls, to discuss the outstanding FERC directives and, given their experience with the Existing MOD C Standards, ways to improve those standards. The informal group also conducted industry outreach to obtain feedback on the Existing MOD C Standards.

In discussing these Reliability Standards, the informal participants concluded that there is a continued need for NERC's Reliability Standards to address the collection and aggregation of Demand and energy data to help ensure that registered entities and the ERO continue to have complete and accurate data necessary for conducting the reliability assessments that are vital to understanding and identifying the reliability needs of the Bulk-Power System. The informal group proposed to consolidate the Existing MOD C Standards into a single, more easily understandable Reliability Standard that responded to Commission directives and comprehensively addressed the data requirements and reporting procedures in a clear and efficient manner. Because Reliability Standard MOD-020-0 applies to the operational time frame, as opposed to the planning horizon to which the Existing MOD C Standards apply, it was not included in the proposed Reliability Standard nor is it proposed for retirement. The proposed Reliability Standard, however, addresses the outstanding Commission directive related to MOD-020-0, as discussed below.

Following the July 18, 2013 posting of the Standard Authorization Request along with the informal participant's draft of proposed MOD-031-1 for a 45-day formal comment period and ballot, a standard drafting team was formed. As further described in Exhibit F hereto, drafts of the proposed Reliability Standard were posted for two additional 45-day comment periods and ballots to address industry comment. The third additional ballot received a quorum of 76.92% and an approval of 83.40%. The final ballot received a quorum of 80.37% and an approval of 90.00%. On May 7, 2014, the NERC Board of Trustees approved proposed Reliability Standard MOD-031-1, the proposed new and modified definitions used therein, and the retirement of the Existing MOD C Standard.

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, proposed Reliability Standard MOD-031-1 satisfies the Commission's criteria in Order No. 672 and is 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 Standard; (2) a discussion of each of the requirements in the proposed Reliability Standard; (3) an explanation of how the proposed Reliability Standard satisfies outstanding Commission directives from Order No. 693; and (4) a discussion of the enforceability of the proposed Reliability Standard.

A. Basis and Purpose of the Proposed Reliability Standard

The proposed Reliability Standard serves the vital reliability goal of establishing a framework for the collection and aggregation of Demand and energy data necessary to support the development of Bulk-Power System reliability assessments. As noted above, a fundamental test for determining the reliability of the Bulk-Power System is an assessment of whether there is an adequate amount of resources available to serve peak Demand while also maintaining a sufficient margin to address operating events. Planners and operators of the Bulk-Power System, policy makers, and governmental authorities rely on the results of these assessments to identify system reinforcements, such as whether to construct new generation or transmission infrastructure, that are necessary for the continued reliable operation of the Bulk-Power System.

Studying whether existing and planned Bulk-Power System resources and transmission infrastructure are sufficient to meet current and projected future Demand requires the collection and aggregation of Demand and energy forecasts on a normalized basis from those functional entities (i.e., Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers) that develop such data. A forecast on a normalized basis is a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak).[34] These forecasts form the baseline for assessing resource adequacy and are a significant factor in achieving Reliable Operation.

Additionally, there is a need to obtain historical data to compare past forecasts with the actual data. Such comparisons are necessary to improve forecasting methods and enhance the accuracy of the forecasts. The accuracy of Demand and energy forecasts is vital to the development of reliability assessments that provide the correct signals to owners and operators of the Bulk-Power System with respect to resource adequacy. Underestimating load growth and/or Net Energy for Load can result in insufficient or inadequate generation and transmission facilities and may cause reliability issues during Real-time operations. Conversely, overestimating load growth and/or Net Energy for Load can result in over-investment in infrastructure and under-utilization of network capacity.

The proposed Reliability Standard is designed to replace, consolidate and improve upon the Existing MOD C Standards in addressing the collection and aggregation of the actual and forecast Demand and energy data necessary to perform complete and accurate reliability assessments. Like the Existing MOD C Standards, proposed Reliability Standard MOD-031-1

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[34] Normalized forecasts are used to test against more extreme conditions.

support both the reliability assessments prepared by the ERO and those prepared by various Bulk-Power System planners and operators to assess resource adequacy in their areas. The ERO prepares seasonal and long-term assessments of the overall reliability and adequacy of the North American Bulk-Power System. For these assessments, the ERO divides the Bulk-Power System into assessment areas, both within and across the boundaries of the eight Regional Entities. The preparation of these assessments involves the collection and consolidation of data provided by the Regional Entities, including forecasts for on-peak Demand and energy, demand response, resource capacity, and transmission projects. The Regional Entities currently obtain the Demand and energy data used in these assessment by requesting the information from the relevant functional entities pursuant to the Existing MOD C Standards. Proposed Reliability Standard MOD-031-1 continues to require entities to provide their data to Regional Entities, upon request, to facilitate the EROs reliability assessments.

The proposed Reliability Standard also continues to provide planners and operators of the Bulk-Power System access to complete and accurate Demand and energy data to allow such entities to conduct their own resource adequacy analyses. By providing for consistent documentation and information sharing practices for Demand and energy data, proposed MOD-031-1 promotes efficient planning practices across the industry and supports the identification of needed system reinforcements.

Proposed Reliability Standard MOD-031-1 improves upon the existing MOD C Standards by consolidating the five Existing MOD C Standards into a single, streamlined standard that provides authority for applicable entities to collect Demand and energy data, and related information to support reliability assessments. The proposed Reliability Standard enumerates the responsibilities of applicable entities with respect to the provision and/or collection of such data.

Proposed Reliability Standard MOD-031-1 also addresses Commission directives from Order No. 693[35] to modify the Existing MOD C Standards, as discussed below.

B. Requirements in the Proposed Reliability Standard

Proposed Reliability Standard MOD-031-1 provides an efficient and enforceable mechanism for entities that conduct reliability assessments to obtain all of the Demand and energy data that is necessary to accurately assess resource adequacy. The data subject to the standard falls into three general categories: (1) Total Internal Demand; (2) Net Energy for Load; and (3) Demand Side Management. The term "Total Internal Demand" is a new term proposed for inclusion in the NERC Glossary. The standard drafting team developed the term in response to industry comment on the proposed Reliability Standard to provide more specificity to the type of Demand data subject to the Reliability Standard. The proposed definition of "Total Internal Demand" is "[t]he Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system."

NERC is also proposing changes to the definition of Demand Side Management, which is currently defined as: "The term for all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." NERC proposes to define "Demand Side Management" as "[a]ll activities or programs undertaken by any applicable entity to achieve a reduction in Demand." Consistent with the Commission directive in Order No. 693, the proposed definition for Demand Side Management is not limited to "activities or program undertaken *by Load Serving Entities or its customers*" but is expanded to include "activities or

[35] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222 (2007), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

programs undertaken by *any applicable entity*." Additionally, the standard drafting team determined that to more accurately reflect the purpose of Demand Side Management activities and programs, the definition should include the phrase "to achieve a reduction in Demand" instead of "to influence the amount or timing of electricity they use."

Proposed Reliability Standard MOD-031-1 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. Proposed Reliability Standard MOD-031-1 consists of four requirements, as follows:

- *Requirement R1* mandates that each Planning Coordinator or Balancing Authority that identifies a need for the collection of Demand and energy data shall develop and issue a data request for such data from relevant entities in their area. The requirement mandates that the data request clearly identify: (i) the entities responsible for providing the data; (ii) the data to be provided by each entity; and (iii) the schedule for providing the data. Requirement R1 also specifies the type of Demand and energy data that may be requested under the proposed Reliability Standard.

- *Requirement R2* obligates the entities identified in a data request issued pursuant to Requirement R1 to provide the requested data to their Planning Coordinator or Balancing Authority, as applicable, pursuant to the format and schedule specified in the data request.

- *Requirement R3* requires that the Planning Coordinator or the Balancing Authority, as applicable, provide the data collected under Requirement R2 to their Regional Entity, upon request, to facilitate the ERO's development of reliability assessments.

- *Requirement R4* requires entities to share their Demand and energy data with any Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner that demonstrates a reliability need for such data, subject to applicable confidentiality, regulatory or security restrictions. The requirement to share such data helps ensure that planners and operators of the Bulk-Power System have access to complete and accurate data necessary to conduct their own resource adequacy assessments.

The following is a discussion of each of the four requirements in proposed MOD-031-1:

<u>Requirement R1</u> provides:

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2 A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary: **1.4.1.** Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

Requirement R1 consolidates the requirements from the Existing MOD C Standards related to the development of data requirements and reporting procedures for Demand and energy data.[36] Like Reliability Standard MOD-016-1.1, the Planning Coordinator plays a central role in the collection and aggregation of Demand and energy data under the proposed Reliability Standard. It is appropriate to designate the Planning Coordinator as one of the entities to collect the data because, as described in the NERC Functional Model, it is the functional entity that coordinates, facilitates, integrates and evaluates transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.[37] Balancing Authorities were also included to reflect that, in certain regions, Balancing Authorities collect and aggregate Demand and energy data used for reliability

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[36] Exhibit D to this Petition is a mapping document comparing the existing MOD C Standards to proposed MOD-031-1.

[37] Additionally, the Functional Model states that Planning Coordinators are responsible for the collection of the following information: transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators; Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners; generator unit performance characteristics and capabilities from Generator Owners; and long-term capacity purchases and sales from Transmission Service Providers.

assessments.[38] Requirement R1 was drafted to allow entities to continue their existing data collection practices.[39]

Requirement R1 establishes the universe of Demand and energy data that entities may be compelled to provide under the proposed Reliability Standard and mandates that any requests for such data contain certain basic elements to help ensure that data is provided in a timely and accurate manner. When a Planning Coordinator or Balancing Authority issues a data request pursuant to Requirement R1, the data request must include: (i) a list of entities responsible for providing the data (the "Applicable Entitles") (Part 1.1); (ii) the schedule for providing the data, which can be no less than 30 days from the date of the request (Part 1.2); and (iii) the data to be provided (Part 1.3-1.5). These elements help to ensure that reporting entities are properly notified whether they must provide data, what data to provide, and when they must provide the data.

Part 1.1 identifies the functional entities (i.e., Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers) that may be required to provide Demand and energy data under the proposed Reliability Standard. The list of entities tracks the entities responsible for providing data under the Existing MOD C Standards, except for the addition of Transmission Planners and the removal of Resource Planners. Transmission Planners were included because, as the Commission notes in Order No. 693, they are responsible for collecting, and in some cases developing, system modeling data, including actual and forecast load, to evaluate transmission expansion plans. In contrast, Resource Planners do not develop any

[38] For instance, Balancing Authorities serve this function in the Western Electricity Coordinating Council region.

[39] The standard drafting team concluded that such diversity of practice is acceptable from a reliability perspective.

of the data requested under the proposed Reliability Standard. As such, the standard drafting team concluded that it was appropriate not to include Resource Planners in the list of entities in Part 1.1.

Parts 1.3-1.5 identify the Demand and energy data, and related information that entities must provide to support the development of reliability assessments. As explained below, Parts 1.3-1.5 carry forward the data included in the Existing MOD C Standards, as illustrated in Exhibit D. Compared to the Existing MOD C Standards, however, Parts 1.3-1.5 add specificity and clarity to the data requirements. Additionally, consistent with Commission directives, Parts 1.3-1.5 expands the list of data that may be requested to help ensure that entities that perform reliability assessments have all the necessary data to develop complete and accurate assessments.

In particular, Part 1.3 identifies the historical Demand and energy data that entities must provide upon request. As noted above, the collection of actual Demand and energy data is necessary to compare past forecasts with the actual data to improve the accuracy of the forecasts. Subparts 1.3.1, 1.3.2 and 1.3.3 include the data now covered by Reliability Standard MOD-017-0.1, Requirements R1.1 and R1.2. Part 1.3 adds specificity to the Existing MOD C Standard by using the NERC Glossary term for "Demand" and adds clarity by stating that the data to be provided is for the "prior *calendar* year" rather than just the "prior year." Consistent with the Commission's directive,[40] the standard drafting team added Part 1.3.2.1 to require entities whose annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), to also report the "*weather normalized* annual peak hour actual Demand for the prior calendar year."[41] Weather normalized Demand data is actual Demand data that has

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40 Order No. 693 at P 1249.

41 For those entities whose load does not vary with temperature, humidity, or other related conditions, there is no need to require them to report weather normalized data because it would be the same as the actual data reported under Part 1.3.2.

been adjusted to account for weather effects (i.e., what the actual demand would have been under normal or expected weather conditions). Because weather condition can significantly affect the level of Demand, it is important to account for weather effects when comparing past Demand forecasts to the actual Demand. As the Commission recognized in Order No. 693, weather normalized data allows for meaningful comparison with forecasted values.[42]

Additionally, the standard drafting team added part 1.3.4 to require the reporting of "monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator" for the prior calendar year. The standard drafting team concluded that such data is necessary to analyze the "accuracy, error and bias of controllable load forecasts," consistent with the Commission's directive.[43] The phrase "controllable and dispatchable Demand Side Management" was used so as to have a single phrase throughout the proposed Reliability Standard that would cover both Interruptible Demand as well as Direct Control Load Management.[44]

Part 1.4 identifies the forecast Demand and energy data that must be provided upon request. As noted above, the forecast data identified in Part 1.4 forms the baseline for assessing resource adequacy. Subparts 1.4.1 through 1.4.4 include the data now covered by Reliability Standard MOD-017-0.1, Requirements R1.3 and R1.4, and Subpart 1.4.5 includes the data now covered by MOD-019-0, Requirement R1. Part 1.4 adds specificity and clarity to the Existing MOD C Standard by: (1) using the newly defined phrase "Total Internal Demand" in Parts 1.4.1 and 1.4.3

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[42] Order No. 693 at P 1249.

[43] *Id*. at P 1276.

[44] Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." Direct Control Load Management ("DCLM") is defined as "Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand." The phrase controllable and dispatchable Demand Side Management is broad enough to cover both defined terms.

instead of the word "demand" so as to more specifically describe the Demand data to be forecasted; and (2) using the phrase "controllable and dispatchable Demand Side Management…under the control and supervision of the System Operator" instead of "interruptible demands and Direct Control Load Management (DCLM)," for the reasons noted above; and (3) clarifying that the forecasts are for "calendar years."

Part 1.5 identifies the related information that must be provided to enable system planners and the ERO to better understand and evaluate the forecasts provided pursuant to Part 1.4 of Requirement R1. Collectively, the information required by Part 1.5 will help to ensure that those entities that perform reliability assessments have insight into the assumptions, methods and accuracy of the forecasts underlying the assessments. Subpart 1.5.1 carries forward the information now covered by Reliability Standard MOD-018-0, Requirement R1.2. Subparts 1.5.2 and 1.5.3 carry forward the information now covered by Reliability Standard MOD-021-0, Requirements R1.1 and R1.2, respectively. As explained further below, Subparts 1.5.4 and 1.5.5 address the Commission's directives to require the reporting of the accuracy, error, and bias of (1) load forecasts with due regard to temperature and humidity variations, and (2) controllable load forecasts.[45] These two additional explanations will require forecasting entities to explain the accuracy, error and bias of their forecasts as well as the steps they have taken to improve their forecasting methods.

Lastly, Requirement R1 applies when a Planning Coordinator or Balancing Authority "identifies a need" for the collection of Demand and energy data." This language is intended to reflect that certain Planning Coordinators and Balancing Authorities may not need to collect Demand and energy data through a data request issued pursuant to the proposed Reliability

[45] Order No. 693 at PP 1251, 1276.

Standard. That is because certain Planning Coordinators and Balancing Authorities obtain the necessary Demand and energy data through alternative mechanisms or develop the data themselves. For instance, many Planning Coordinators, such as independent system operators ("ISOs") and regional transmission organizations ("RTOs"), collect the necessary data and information from entities within their footprint pursuant to requirements in their Open Access Transmission Tariffs. Additionally, ISOs/RTOs are often in a better position to develop the necessary Demand and energy forecasts or aggregate the historical data than the entities in their area. Accordingly, the requirement is drafted so as to only require a Planning Coordinator or Balancing Authority to issue a data request if there is a need to do so.

Requirement R2 provides:

> **R2.** Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.

Requirement R2 will ensure that Applicable Entities provide the Demand and energy data requested by their Planning Coordinator or Balancing Authority, as applicable, pursuant to Requirement R1. The intent of the requirement is to reinforce and emphasize accountability for those entities that are in the best position to have and provide the necessary data.

Requirement R3 helps ensure that the Planning Coordinator or, when applicable, the Balancing Authority, provides the data collected pursuant to Requirement R2 to the Regional Entity to support the reliability assessments performed by the ERO. Requirement R3 provides:

> **R3.** The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties.

The standard drafting team determined that 75 calendar days was an appropriate time frame for providing the data to the Regional Entity to accommodate the time it would take the Planning

Coordinator or Balancing Authority to collect the data from Applicable Entities under Requirement R2 and then package that data for the Regional Entity.

Requirement R4 requires applicable entities to share their Demand and energy data to help ensure that planners and operators of the Bulk-Power System have access to complete and accurate data necessary to conduct their own resource adequacy assessments. The requirement to share data amongst entities will improve the efficiency of planning practices and ultimately enhance the reliability of the Bulk-Power System. Requirement R4 provides as follows:

> **R4.** Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity:
>
> - shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and
> - shall not be required to alter the format in which it maintains or uses the data.
>
> **4.1.** If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

To reduce the burdens associated with data sharing, Requirement R4 sets forth the following parameters:

- The only entities that may obtain the data are Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for the data to conduct their own reliability assessments. This will prevent entities from requesting data for purposes unrelated to reliability.

- Applicable entities are only required to provide the data included in Parts 1.3-1.5 of Requirement R1. An applicable entity may voluntarily provide additional data but cannot be compelled to do so under the proposed requirement.

- Applicable entities are not required to alter the format in which it maintains or uses the data.
- Lastly, applicable entities are not required to share data if it conflict with the applicable entity's confidentiality, regulatory, or security requirements.

If an applicable entity does not provide some or all of the data requested because (1) the requesting entity did not demonstrate a reliability need for the data, or (2) providing the data would conflict with the entity's confidentiality, regulatory, or security requirements, the applicable entity is required to provide a written response specifying the data that is not being provided and on what basis. This requirement will help ensure that applicable entities do not unjustifiably withhold data.

C. Proposed MOD-031-1 Satisfies Outstanding Commission Directives

As noted, Project 2010-04 Demand Data (MOD C) was initiated to address outstanding FERC directives from Order No. 693. The following is a discussion of each of those directives and the manner in which proposed MOD-031-1 addresses those directives.

Applicability to Transmission Planners: The Commission directed NERC to modify MOD-016-1 and MOD-017-0 to expand the applicability section to include Transmission Planner because under the NERC Functional Model the Transmission Planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans.[46] Consistent with this directive, Transmission Planners are included in the applicability section of proposed MOD-031-1 and, pursuant to Requirement R2, are required to provide Demand and energy data upon request.

Definition of Demand Side Management: The Commission directed NERC "to add to its definition of DSM 'any other entities' that undertake activities or programs to influence the amount

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46 Order No. 693 at PP 1232; 1255.

or timing of electricity they use without violating other Reliability Standard Requirement."[47] The standards drafting team modified the definition of Demand Side Management to be consistent with FERC's directive and to add clarity, as discussed above.

Reporting of Temperature and Humidity Data: The Commission directed NERC to modify MOD-017-0 to require the "reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values."[48] The Commission stated that collecting this data "will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability."[49] Rather than requiring entities to report actual temperature and humidity data, however, Subpart 1.3.2.1 requires entities whose peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed) to provide their weather normalized annual peak hour actual Demand for the prior calendar year. The standard drafting team determined that this approach meets the goal of the Commission's directive to get weather normalized data in a more efficient and an equally effective manner. This approach places the responsibility on each load forecasting entity to weather normalize their Demand data based on the particular weather conditions that affect their actual Demand. Whereas temperature and humidity play a large role in some regions, Demand in other regions is more affected by different weather conditions, such as wind speed. As such, simply requiring the reporting of temperature and humidity data may not provide the aggregators of the data (i.e., Planning Coordinators or Balancing Authorities) all the necessary information to weather normalize the data. The standard

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47 Order No. 693 at P 1232.

48 *Id*. at P 1249.

49 *Id*.

drafting team concluded that the load forecasting entities are in the best position to effectively weather normalize their Demand data in a timely manner.

In Order No. 693, the Commission also directed NERC to consider whether to exempt entities from the reporting of temperature and humidity if their load does not vary with temperature and humidity.[50] Subpart 1.3.2.1 only requires entities to report weather normalized actual demand data if their Demand varies due to weather-related conditions. For those entities whose load does not vary with temperature, humidity, or other weather-related conditions, there is no need to require them to report weather normalized data because it would be the same as the actual data reported under Part 1.3.2

Reporting of Accuracy, Error and Bias of Load Forecasts Compared to Actual Loads: The Commission directed NERC to modify MOD-017-0 to "require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations."[51] The Commission stated that "[m]easuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves."[52] Requirement R1, Subpart 1.5.5 of the proposed Reliability Standard satisfies this directive by requiring load forecasting entity to explain "[h]ow the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted." These explanations will describe the accuracy, error and bias of load forecasts, consistent with the Commission's directive. As

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50 Order No. 693 at P 1250.

51 *Id*. at P 1251.

52 *Id*.

noted by the Commission, this information "is important [] for system planners to include in their studies, and also improves load forecasts themselves."[53]

Correcting Load Forecasts: Consistent with the Commission directive to modify MOD-017-0 to "add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias,"[54] entities are required, pursuant to Subpart 1.5.5 of Requirement R1 to provide an explanation of "how the assumptions and methods for future forecasts were adjusted" based on a comparison of peak Demand forecasts and actual Demand for the prior year. This requirement will promote changes to an entity's forecasting practices to increase the accuracy of those forecasts.

Exceptions to Provide Hourly Demand Data: The Commission disagreed with a "recommendation to allow some exceptions to the requirement [in MOD-017-0] to provide hourly demand data" but, recognizing that the "metering for some customer classes may not be designed to provide certain types of data," directed the ERO to consider this issue in the Reliability Standards development process.[55] The standards drafting team concluded that there should not be any such exceptions as the reporting of hourly load data is necessary to accurately model the Bulk-Power System. The proposed Reliability Standard also provides Planning Coordinators and Balancing Authorities the flexibility to modify their data requests to accommodate the capabilities of entities in their area.

Small Entities: The Commission directed NERC to consider whether small entities should be required to comply with MOD-018-0 because their forecasts are not significant for reliability

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53 Order No. 693 at P 1251.

54 *Id*. at P 1252.

55 *Id*. at P 1256.

purposes.[56] The standard drafting team concluded that it was not appropriate to categorically exempt all small entities. Rather, the standard drafting team determined it was more appropriate to provide Planning Coordinators and Balancing Authorities, the functional entities that have a broader view of the significance of an entity's forecast to their area, the discretion as to whether to require small entities to provide that data. Should a small entity disagree with their Planning Coordinator or Balancing Authority on the need for such data, the entity may, in its response to the data request, explain why its forecasts are not significant and request that it not be required to submit the data prospectively.

Reporting of the Accuracy, Error and Bias of Controllable Load Forecasts: The Commission directed NERC to modify MOD-019-0 to add a requirement for the reporting of the accuracy, error and bias of controllable load forecasts.[57] The Commission stated that "this requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments."[58] Consistent with the Commission's directive, Requirement R1, Subpart 1.5.4 of the proposed Reliability Standard requires entities to explain "[h]ow the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted." Additionally, as noted above, Part 1.3.4 requires entities to submit their actual Demand Side Management data, which will allow for comparison to prior forecasts.

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56 Order No. 693 at P 1265.

57 *Id*. at P 1276.

58 *Id*.

Analysis of Actual and Forecast Demands for Five Years for Actual Controllable Load: The Commission directed NERC to add a new requirement to MOD-019-0 that would obligate Resource Planners to analyze differences between actual and forecasted Demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.[59] The standard drafting team concluded that the intent of this directive is satisfied by Requirement R1, Subpart 1.5.4, which requires entities to explain "how the assumptions and methods for future forecasts were adjusted" based on a comparison of controllable and dispatchable Demand Side Management forecast forecasts to the actual controllable and dispatchable Demand Side Management for the prior calendar year. This requirement will promote changes to an entity's forecasting practices to increase the accuracy of those forecasts. Additionally, the proposed Reliability Standard requires entities to submit their actual Demand Side Management data, which will allow for an analysis of the actual data to prior forecasts.

Standardization of Principles on Reporting and Validating DSM Program Information: FERC directed NERC to add a requirement to MOD-021-0 for standardization of principles on reporting and validating Demand Side Management program information.[60] To address this directive, the proposed Reliability Standard requires applicable entities to provide an explanation of (1) the Demand and energy effects of Demand Side Management; (2) the manner in which they forecast Demand Side Management; and (3) how such forecasts are adjusted to account for bias and errors. (Requirement R 1.5.3). These explanations will, consistent with the Commission's directive, allow system planners and operators to understand how Demand Side Management

[59] Order No. 693 at P 1277.

[60] *Id*. at P 1298.

program information is reported and validated, and, in turn, provide for a consistent and uniform evaluation of demand response.

D. Enforceability of the Proposed Reliability Standards

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

The proposed Reliability Standard also includes 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.[61]

V. EFFECTIVE DATE

As described in the implementation plan attached hereto as Exhibit B, NERC respectfully requests that the Commission approve the proposed Reliability Standard, the proposed new and modified NERC Glossary terms and the retirement of the Existing MOD C Standards, effective on the first day of the first calendar quarter that is twelve months after Commission approval. This 12-month implementation period is designed to provide applicable entities sufficient time to transition from compliance with the Existing MOD C Standards to proposed Reliability Standard MOD-031-0. The standard drafting team concluded that a 12-month implementation period is

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[61] 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.").

appropriate as entities will need time to develop new processes or modify their existing processes to comply with the proposed Reliability Standard.

VI. <u>CONCLUSION</u>

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

- the proposed Reliability Standard and associated elements included in Exhibit A, effective as proposed herein;
- the proposed implementation plan included in Exhibit B;
- the proposed definitions for the terms Demand Side Management and Total Internal Demand, effective as proposed herein; and
- the retirement of the currently effective Reliability Standards MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1, effective as proposed herein.

Respectfully submitted,

<u>/s/ S. Shamai Elstein</u>

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Date: May 13, 2014

Exhibit A

Proposed Reliability Standard

A. Introduction

1. **Title: Demand and Energy Data**

2. **Number: MOD-031-1**

3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "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 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

   The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and

Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

- **1.4.1.** Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.
- **1.4.2.** Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.
- **1.4.3.** Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.
- **1.4.4.** Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.
- **1.4.5.** Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

- **1.5.1.** The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.
- **1.5.2.** The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.
- **1.5.3.** How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
- **1.5.4.** How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.
- **1.5.5.** How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and
- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

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	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to 91

			did so after 75 days from the date of request but prior to 81 days from the date of the request.	did so after 80 days from the date of request but prior to 86 days from the date of the request.	did so after 85 days from the date of request but prior to 91 days from the date of the request.	days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees.	

Rationale

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

Rationale for R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

Exhibit B

Implementation Plan

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Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

> **Demand Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
>
> **Total Internal Demand:** The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

The defined term "Demand Side Management" is incorporated in the NERC approved standards listed in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand Side Management," it is not anticipated that the proposed revision will have any effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

NERC

Conforming Changes to Other Standards
None

Effective Dates

MOD-031-1 shall become effective as follows:

The first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Demand-Side Management"

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term "Demand-Side Management"

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

Exhibit C

Order No. 672 Criteria

EXHIBIT C

<u>Order No. 672 Criteria</u>

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 Standard MOD-031-1 achieves the specific reliability goal of ensuring that Demand and energy data necessary to support reliability assessments conducted by the ERO and Bulk-Power System planners and operators is available to such entities. The proposed Reliability Standard enumerates the responsibilities of applicable entities with respect to the provision and/or collection of Demand and energy data. By providing for consistent documentation and information sharing practices for the collection and aggregation of such data, proposed Reliability Standard MOD-031-1 promotes efficient planning practices and supports the identification of needed system reinforcements. Furthermore, the requirement in the proposed Reliability Standard to report historical Demand, Net Energy for Load and Demand-Side Management data will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. These activities ultimately enhance the reliability of the Bulk Electric System.

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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 PP 321, 324.

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 Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Planning Coordinators, Transmission Planners, Balancing Authorities, Resource Planners, Load Serving Entities and Distribution Providers. The proposed Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

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 Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at PP 322, 325.

[4] Order No. 672 at P 326.

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 each requirement by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which 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 Standard achieves the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to the provision and/or collection of Demand and energy data necessary to support reliability assessments. Proposed MOD-031-1 consolidates and streamlines the Existing MOD C Standards to more efficiently address the collection and aggregation of Demand and energy data.

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

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant benefits for the

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[5] Order No. 672 at P 327.

[6] Order No. 672 at P 328.

[7] Order No. 672 at P 329-30.

Bulk-Power System. The requirements of the proposed Reliability Standard help ensure that entities that conduct reliability assessments, which are fundamental to analyzing the reliability of the grid, have access to complete and accurate data necessary to conduct those assessments.

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 Standard applies throughout North America and does not favor one geographic area or regional model. In fact, the proposed Reliability Standard supports the various ways in which Demand and energy data is collected across the continent.

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

The proposed Reliability Standard has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities in the provision or collection of Demand and energy data. The standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

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[8] Order No. 672 at P 331.

[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.

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

The proposed effective date for the standard is just and reasonable and appropriately balances the urgency in the need to implement the standard 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 date is explained in the proposed Implementation Plan, attached as Exhibit B.

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 Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standards. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots 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 Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

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[10] Order No. 672 at P 333.

[11] Order No. 672 at P 334.

[12] Order No. 672 at P 335.

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

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

[13] Order No. 672 at P 323.

Exhibit D

Mapping Document

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Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R3	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirements R2 and R4	Requirements R2 and R4 of the standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5.
MOD-017-0.1 R1.1	Requirement R1 part 1.3.1	The standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.3.2	The standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.4.1	The standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.4.2	The standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	Omitted	This is no longer need now that all registered entities within each region is a member of that region.
MOD-018-0 R1.2	Requirement R1 part 1.5.1	The standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirements R2 and R4	The standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.4.3	The standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.5.2	The standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.5.3	The standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The standard will require entities to provide the requested data by a certain date.

Exhibit E

Analysis of Violation Risk Factors and Violation Security Levels

Violation Risk Factor and Violation Severity Level Justifications

MOD-031-1 – Demand and Energy Data

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-031-1 – Demand and Energy Data. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, 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 of a medium risk requirement 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, 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.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification – MOD-031-1 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R1 prescribes data that may be collected for analysis. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R1 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to collect data.

VSL Justification – MOD-031-1 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The Requirement is binary and therefore has one VSL.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and therefore has on VSL, severe. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3:	The proposed VSL is consistent with the corresponding requirement.

Violation Severity Level Assignment Should Be 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 proposed VSL is not based on a cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R2 ensures that once data is collected, it is passed on to the appropriate entity. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard:

	All of the parts within Requirement R2 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2:	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2a: The proposed VSL is not binary Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently 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 proposed VSL is not based on cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R3 ensures that once data is collected, it is passed on to the appropriate entity. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R3 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL is worded consistently with the corresponding requirement.

Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R4 ensures that neighboring entities have the ability to collect data. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R4 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the

	standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary

Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently 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 proposed VSL is not based on cumulative number of violations.

Exhibit F

Summary of Development History and Record of Development

Summary of Development History

The development record for proposed Reliability Standard MOD-031-1 is 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, in part, from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit F.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was submitted to the Standards Committee ("SC") on July 18, 2013 and accepted by the SC on July 18, 2013.

B. First Posting

Proposed Reliability Standard MOD-031-1 was posted for a 45-day formal comment period from July 24, 2013 through September 4, 2013. There were 45 sets of responses, including comments from approximately 110 different people from approximately 100 companies representing 8 of the 10 industry segments. The proposed Reliability Standards received a quorum of 81.96% and an approval of 55.76%.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard MOD-031-1 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).

Purpose Statement and Definitions

- In response to comments on the NERC Glossary term "Demand Side Management," the standard drafting team revised the definition to provide additional clarity.

- In response to comments that it was not clear as to what Demand data was subject to the proposed standard, the standard drafting team developed a definition for Total Internal Demand.

- A commenter stated that the purpose statement and the title of the proposed standard only referenced Demand data but the requirement also requested energy data. In response, the standard drafting team modified the title as well as the purpose statement to address their concern. The standard drafting team also modified the Purpose Statement to remove ambiguity and provide clarity that the intent of the standard is to define the responsibilities of both the requestor of the data and the respondent to the request as well as the data that could be requested.

Requirement R1

- The standard drafting team modified the Requirement R1 to clarify the entities that may request data and the types of data such entities could request.

- A commenter stated that Requirement R1 was open ended such that the data being requested may not be able to be collected within the time allowed. In response, the standard drafting team modified the requirement to limit the data that could be collected to only that which was outlined in the sub-parts. The standard drafting team also modified the language to allow for "any or all" of the data to be requested.

- The standard drafting team modified the language in the sub-parts to provide additional clarity as to the type of data being requested.

- The standard drafting team removed the sub-requirement for an entity to identify entities within their footprint that were not part of their region.

Requirement R2

- The standard drafting team modified Requirement R2 to clearly identify to whom the data owners should respond to for data requests developed under Requirement R1.

- The standard drafting team removed the language from Requirement R2 allowing other neighboring entities to request data as it was felt that there were ambiguity in the language concerning who was requesting data and what data could be requested. The standard drafting added a new requirement (Requirement R4) to address this issue and clearly identify the neighboring entities that could request data.

Requirement R3

- The standard drafting team modified the language in Requirement R3 to clearly state that the Planning Coordinator or Balancing Authority had an obligation to provide data collected to the Regional Entity when the Regional Entity requested the data.

- The standard drafting team added a minimum time frame for responding to a data request from a Regional Entity.

Requirement R4

- The standard drafting team removed the language from Requirement R2 that dealt with allowing neighboring entities the right to request data and created Requirement R4 to allow for this situation.

C. Second Posting

Proposed Reliability Standard MOD-031-1 was posted for a second 45-day formal comment period from October 9, 2013 through November 22, 2013. There were 43 sets of responses, including comments from approximately 144 different people from approximately 94 companies representing 9 of the 10 industry segments. The proposed Reliability Standards received a quorum of 80.54% and an approval of 57.59%.

The standard drafting team considered stakeholder comments regarding proposed Reliability Standard MOD-031-1 and made the following modifications based on those comments:

Purpose Statement and Definitions

- In response to comments regarding the NERC Glossary term Demand Side Management (DSM), the standard drafting team revised the definition to provide clarity that DSM can be achieved through a request or other means such as incentive programs or a market signal/mechanism.

- The standard drafting team made modifications to the definition of Total Internal Demand to provide additional clarity.

- The standard drafting team modified the purpose statement to clarify the reliability purpose of the standard. Specifically, the standard drafting team modified the purpose statement to reflect that the standard provides authority for entities that may otherwise lack authority to collect the specific reliability data.

<u>Requirement R1</u>

- In response to comments concerning the use of the term "may" within the requirement, the standard drafting team modified the requirement.

- The standard drafting team modified the requirement to include the term "calendar year".

- The standard drafting team removed the footnote related to PC/BA areas.

- The standard drafting team modified the requirement to clearly identify that only those entities whose Demand varies due to weather-related conditions would need to provide weather normalized data.

<u>Requirement R2</u>

- The standard drafting team modified Requirement R2 to clearly identify applicable Entities that would be responsible for responding to a data request.

<u>Requirement R3</u>

- In response to comments that the second sentence in the requirement did not provide any additional clarity, the standard drafting team modified the requirement and removed the sentence.

<u>Requirement R4</u>

- In response to comments disagreeing with having LSE or DP be compliant with Requirement R4, the standard drafting team modified the requirement. The standard drafting team revised the requirement to remove the LSE and DP from those entities that can request data but they would be required to provide data on request.

D. Third Posting

Proposed Reliability Standard MOD-031-1 was posted for a 45-day public comment period from February 25, 2014 through April 10, 2014. There were 33 sets of comments, including comments from approximately 119 different people from approximately 73 companies representing 9 of the 10 industry segments. The proposed Reliability Standards received a quorum of 76.92% and an approval of 83.40%.

The standard drafting team considered stakeholder comments and made no revisions to the proposed Reliability Standard MOD-031-1 based on those comments.

E. Final Ballot

Proposed Reliability Standard MOD-031-1 was posted for a 10-day final ballot period from April 25, 2014 through May 5, 2014. The proposed Reliability Standards received a quorum of 80.37% and an approval 90.00%.

F. Board of Trustees Approval

Proposed Reliability Standard (MOD C) MOD-031-1 was approved by NERC Board of Trustees on May 6, 2014.

Record of Development

Project 2010-04 Demand Data (MOD C)

Related Files

Status:

A final ballot for **MOD-031-1 – Demand and Energy Data** concluded at **8 p.m. Eastern on Monday May 5, 2014**. The standard achieved a quorum and received sufficient votes for approval. Voting statistics can be found via the link below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background:

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the "MOD C" standards), were approved in the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 - Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
  - Is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 - Aggregated Actual and Forecast Demands and Net Energy for Load
  - Provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 - Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
  - Provides for the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 - Reporting of Interruptible Demands and Direct Control Load Management
  - Provides for the collection of interruptible demands and direct control load management.
- MOD-021-1 - Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts
  - Provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC's Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC's Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

Although a pure data reporting standard would be a candidate for retirement under Paragraph 81, the data being collected has a reliability purpose in the development of future assessments for resource adequacy. It was decided to present a pro forma standard that consolidates the remaining five MOD C standards into a single standard. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

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

Draft	Action	Dates	Results	Consideration of Comments
MOD-031-1 **Clean (59)|Redline to last posting (60)** **Implementation Plan** **Clean (61)|Redline to last posting (62)** **Supporting Materials:** **Standard Authorization Request (63)** **Compliance Input (64)** **Technical White Paper** **Clean (65)|Redline to last posting (66)** **Mapping Document** **Clean (67)| Redline to last posting (68)** **Draft Reliability Standard Audit Worksheet** **MOD-031-1 (69)** **VRF and VSL Severity Level Justifications (70)**	Final Ballot Info>> **(71)** Vote>>	04/25/14 - 05/05/14	Summary>> **(72)** Ballot Results>> **(73)**	

Draft Standard **MOD-031-1** **Clean (38)|Redline to last posting (39)** **Implementation Plan** **Clean (40)|Redline to last posting (41)** **Supporting Materials:** **Unofficial Comment Form (Word) (42)** **Standard Authorization Request (43)** **Compliance Input (44)** **Technical White Paper** **Clean (45)|Redline to last posting (46)** **Mapping Document** **Clean (47)| Redline to last posting (48)** **Draft Reliability Standard Audit Worksheet** **MOD-031-1 (49)**	Additional Ballot and Non-binding Poll Updated Info>> **(51)** Info>> **(52)** Vote>> (Closed)	04/01/14 - 04/14/14 (Extended an additional day)	Summary>> **(54)** Ballot Results>> **(55)** Non-Binding Poll Results>> **(56)**	
	Comment Period Info>> **(53)** Submit Comments>> (Closed)	02/25/14 - 04/14/14	Comments Received>> **(57)**	Consideration of Comments>> **(58)**

VRF and VSL Severity Level Justifications (50)				
Draft Standard **MOD-031-1** **Clean (18) |Redline to last posting (19)** **Implementation Plan** **Clean (20)|Redline to last posting (21)** **Supporting Materials:** **Unofficial Comment Form (Word) (22)**	Additional Ballot and Non-binding Poll Updated Info>> **(30)** Info>> **(31)** Vote>> (Closed)	11/13/13 - 11/22/13	Summary>> **(33)** Ballot Results>> **(34)** Non-Binding Poll Results>> **(35)**	

Standard Authorization Request (23) **Compliance Input (24)** **Technical White Paper** **Clean (25)|Redline to last posting (26)** **Mapping Document** **Clean (27)| Redline to last posting (28)** **Draft Reliability Standard Audit Worksheet** **MOD-031-1 (29)**	Comment Period Info>> **(32)** Submit Comments>> (Closed)	10/09/13 - 11/22/13	Comments Received>> **(36)**	Consideration of Comments>> **(37)**

Draft Standard **MOD-031-1 (1)** **Implementation Plan (2)** **Standard Authorization Request (3)** **Supporting Materials:** **Unofficial Comment Form (Word) (4)** **Technical White Paper (5)** **Mapping Document (6)** **Compliance Input (7)** **Proposed Timeline for the Formal Development (8)**	MOD-031-1 Ballot and Non-binding Poll Updated Info>> **(9)** Vote>> Closed)	08/26/13 - 09/04/13	Summary>> **(13)** Ballot Results>> **(14)** Non-binding Poll Results>> **(15)** Comments Received>> **(16)**	
	Comment Period Info>> **(10)** Submit Comments>> (Closed)	07/22/13 - 09/04/13		Consideration of Comments>> **(17)**
	Join Ballot Pool>> (Closed)	07/22/13 - 08/20/13		

	Nomination Period Info>> **(11)** Submit Nomination>> Unofficial Nomination Form>> **(12)** (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.

Description of Current Draft

This is the first posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period.

Anticipated Actions	Anticipated Date
45-day SAR Informal Comment Period	July/August 2013
45-day Comment Period with Parallel Initial Ballot	July/August 2013
Recirculation ballot	October 2013
BOT adoption	November 2013

Effective Dates

MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities.

In those jurisdictions where regulatory approval is not required, MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management: The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use.

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: Demand Data**
2. **Number: MOD-031-1**
3. **Purpose:** To ensure that actual and forecast Demand data necessary for assessment and validation of past events and to support future system assessment is reported.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority/Planning Coordinator (hereafter collectively referred to as the "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 "Planning Authority or Planning Coordinator."

   4.1.2 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Background:**

   The fundamental test for determining the adequacy of the Bulk Power System (BPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 forecast (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

   The collection of demand projections requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhance the reliability of the BPS. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure when Planning Coordinators (PC) or Balancing Authorities request data (R1), they identify the entities to provide the data (responsible entity in R1.1), that the entities providing the data know what they are to provide (R 1.3 – R 1.7) and the due dates (R 1.2) for the requested data.

R1. The Planning Coordinator or Balancing Authority, as identified by the Regional Entity in a data request, shall develop and issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include, at a minimum: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entity").

1.2. A schedule detailing the timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. The original data request from the Regional Entity.

1.4. A request for the following actual data[1]:

1.4.1. Integrated hourly demands in megawatts (MW) for the prior year.

1.4.2. Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.

1.4.3. Monthly and annual peak hour weather normalized actual demands in MW for the prior year.

1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW for the prior year.

1.5. A request for the following forecast data[1]:

1.5.1. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.

1.5.2. Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

[1] This could include data reported in the Long Term Reliability Assessment (LTRA) and the EIA 411.

1.5.3. Forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

1.6. A requirement for Applicable Entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported.

1.7. A requirement for Applicable Entities to provide:

1.7.1. The assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.

1.7.2. The Demand and energy effects of Interruptible and Direct Control Load Management.

1.7.3. How DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.7.4. How the peak load forecast compares to actual load for the prior year with due regard to controllable load[2], temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority as identified by the Regional Entity in its data request, shall have a dated data reporting request, either in hardcopy or electronic format, in accordance with Requirement R1.

Rationale for R2: This will ensure that entities identified in Requirement R1, that are responsible for providing data, provide the data in accordance with the details described in the data reporting procedure developed in Requirement R1. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R2. Each Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the Planning Coordinator or Balancing Authority or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner) on request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mail or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

Rationale for R3: This will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

[2] For the purpose of this standard, the term "controllable load" means both interruptible load and direct control load management as referenced in FERC Order 693 Para 1267.

R3. The entity identified by the Regional Entity in its data request, shall report the Applicable Entity's data as requested by the Regional Entity within the timeframe specified in the Regional Entity's request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mail or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

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 R3, and Measures M1 through M3, 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 or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address one of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4.	The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address two of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4. OR The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address one of the items listed in Requirement R1, Part 1.1 through Part 1.3, Part 1.4.1, Part 1.4.2 or Part 1.5.1 through Part 1.5.3.	The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address three of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4. OR The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address two of the items listed in Requirement R1, Part 1.1 through Part 1.3, Part 1.4.1, 1.4.2 or Part 1.5.1 through Part 1.5.3.	The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, did not develop a data reporting procedure. OR The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to issue the data reporting request to the Applicable Entities identified in Requirement R1 Part 1.1. OR The Planning Coordinator or Balancing Authority as identified by the Regional Entity, developed a data reporting procedure but failed to address any of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4. OR

						The Planning Coordinator or Balancing Authority as identified by the Regional Entity, developed a data reporting procedure but failed to address three or more of the items listed in Requirement R1, Part 1.1 through 1.3, Part 1.4.1, Part 1.4.2, or Part 1.5.1 through Part 1.5.3.
R2	Long-term Planning	Medium	N/A	N/A	N/A	The Applicable Entity, as defined in the data reporting request developed in Requirement R1, failed to provide the data requested to the requesting entity as defined in Requirement R1.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The entity as identified by the Regional Entity in its data request, failed to provide the data requested by the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

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Implementation Plan

Project 2010-04 Demand Data

Implementation Plan for MOD-031-1 – Demand Data

Approvals Required
MOD-031-1 – Demand Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

Demand Side Management: The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use.

The proposed revised definition for "Demand-Side Management" is incorporated in the NERC approved standards, detailed in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand-Side Management", it is not anticipated that the proposed revision will have any adverse effect on the standards.

Applicable Entities

Planning Coordinator

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

MOD-001-2 shall become effective as follows:

1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities.
2. In those jurisdictions where regulatory approval is not required, MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Justification

The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements

MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired upon MOD-031-1 becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired upon MOD-031-1 becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Demand-Side Management"

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term "Demand-Side Management"

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Demand Data		
Date Submitted:	July 18, 2013		
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC		
Telephone:	609-613-1848	E-mail:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.
Purpose or Goal (How does this request propose to address the problem described above?):
The pro forma standard consolidates the reliability components of the existing standards.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 693, remove ambiguity from the requirements, and incorporate lessons learned.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
An informal development ad hoc group is presenting a pro forma standard that consolidates the existing MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1 into a single standard. The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. The pro forma standard requirements are currently placed within a new standard, MOD-031-1.
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.)
Detailed description of this project can be found in the Technical White Paper of this SAR submittal package.

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.

Reliability Functions		
☒	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.
☒	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

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.
☐	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
MOD-001-1a	Available Transmission System Capability

Related Standards	
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None

Regional Variances	
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Unofficial Comment Form

Project 2010-04 Demand Data

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft MOD-031-1 standard. The electronic comment form must be completed by 8:00 p.m. ET on **Wednesday, September 4, 2013**

If you have questions please contact Darrel Richardson via email or by telephone at 609-613-1848.

The project page may be accessed by clicking here.

Background Information

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the "MOD C" standards), were approved in the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 - Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
  - Is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 - Aggregated Actual and Forecast Demands and Net Energy for Load
  - Provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 - Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
  - Provides for the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 - Reporting of Interruptible Demands and Direct Control Load Management
  - Provides for the collection of interruptible demands and direct control load management.
- MOD-021-1 - Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts
  - Provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC's Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC's Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

Although a pure data reporting standard would be a candidate for retirement under Paragraph 81, the data being collected has a reliability purpose in the development of future assessments for resource adequacy. It was decided to present a pro forma standard that consolidates the remaining five MOD C standards into a single standard. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

This posting is soliciting comment on a pro forma standard 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-031-1 consolidates and replaces the topics previously addressed by MOD-016 through MOD-019, and MOD-021, in addition to incorporating improvements and approaches to meet remaining directives. Do you agree with the approach in MOD-031-1?

☐ Yes
☐ No

3. If you have any specific comments on MOD-031-1, please indicate them here.

Comments:

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

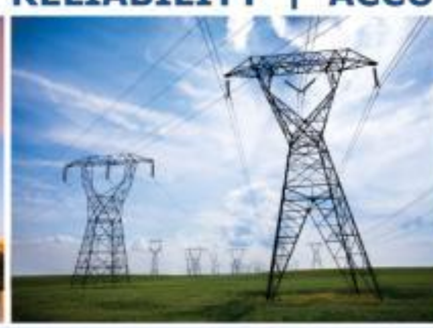
White Paper on the MOD C Standards

MOD-016, MOD-017, MOD-018, MOD-019, and MOD-021

July 18, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the "MOD C" standards), were approved in the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 provides for the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 provides for the collection of interruptible demands and direct control load management.
- MOD-020-0 addresses the need to provide interruptible demands and direct control load management data to System Operators and Reliability Coordinators.
- MOD-021-1 provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC's Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC's Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

Although a pure data reporting standard would be a candidate for retirement under Paragraph 81, the data being collected has a reliability purpose in the development of future assessments for resource adequacy. It was decided to present a pro forma standard that consolidates the remaining five MOD C standards into a single standard, which was supported as the group conducted informal development outreach. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

As detailed below, the MOD C informal ad hoc group discussed the outstanding directives from FERC Order No. 693 and, through the informal development, provided a resolution to address each one.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of collecting data used in the analysis of resource needs. This document outlines the next generation of these standards and proposes to combine the reliability components of this package of standards into one standard. The remaining requirements in this package would either be retired as administrative or captured as instructional or explanatory in a white paper.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how NERC is addressing each of the outstanding FERC directives assigned to these FERC-approved standards. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. The contents of this paper are intended to assist the standard drafting team (SDT) assigned to MOD C and industry stakeholder participants with background information to move this standard package through the formal development process. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

Technical Discussion

The fundamental test for determining the adequacy of the bulk power system (BPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand projections requires coordination and collaboration between Planning Authorities/Planning Coordinators, Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts—as well as the supporting methods and assumptions used to develop these forecasts—will ultimately enhance the reliability of the BPS. Consistent documenting and information-sharing activities will also improve the efficiency of planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and Demand-Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

A second alternative to addressing data requirements in the absence of a standard is the implementation of either a Section 800 or Section 1600 data request. This approach, while effective, has a number of disadvantages. First, some Canadian provinces are not subject to FERC rule, which makes it more difficult for NERC to enforce an 800 or 1600 data request. The second issue is with entities within the continental United States. The 800 or 1600 data request is not mandatory and does not provide a mechanism to compel participation other than pursuing federal action under Section 215 of the Federal Power Act. In addition, using either of these approaches does not provide a mechanism for other LSEs, DPs, BAs or TPs to obtain the data from a neighboring entity.

The recommended option of modifying the existing standards to remove the ambiguity and address the FERC directives solves the issues identified with the first two options. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada. The informal development effort resulted in the recommendation for the development of a standard and has provided a draft version that combines the five existing standards into a single, comprehensive, and clear standard with three requirements.

Outstanding FERC Directives

There are 11 outstanding FERC directives from Order 693. Each of the directives was discussed in detail during the informal development stage, and summaries of the discussions can be found below. The ad hoc group extensively reviewed each of the directives with consideration of where the existing standards are today, where the group landed with the pro forma standard following its extensive industry outreach, and how the group addressed each directive.

The "Paragraph 81 initiative," which was issued by FERC in their March 15, 2012,[1] invited the ERO to identify possible requirements that have little to no effect on reliability that could be removed from the NERC Reliability Standards. The ad hoc group took the information from the FERC order into consideration when it discussed the directives related to the MOD C initiative.

Para 1232

Supported by many commenters, **the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans**. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. **Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.**

Consideration of Directive

With regard to the first directive, the ad hoc group is recommending that the Transmission Planner be added to the Applicability Section of the proposed standard MOD-031-1 Demand Data Reporting.

Regarding the second directive, the ad hoc group is proposing a modified definition for Demand-Side Management (DSM). However, the group felt that the FERC proposed definition needed further clarity, so they modified it in an equally effective and efficient manner. It now reads:

> **Demand-Side Management:** The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

[1] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand Data Reporting. Requirement R1 now requires weather-normalized actual demand data to be reported (Requirement R1 part 1.4.3). The requirement now states that an entity must provide an explanation of how it used temperature and humidity to weather normalize its actual demands (Requirement R1 part 1.7.4).

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length and decided that there should not be an exemption. The group believes that if the load is not weather-sensitive then an explanation will be provided (Requirement R1 part 1.7.4), which will accomplish the same objective as providing an exemption.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand Data Reporting. The requirement now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.7.4).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand Data Reporting. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.7.4).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

The informal ad hoc group, as a result of its informal outreach, is recommending that the Transmission Planner be added to the Applicability Section of the proposed standard MOD-031-1 Demand Data Reporting.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length with industry participants during informal outreach and decided that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length during its outreach and concluded that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

The SDT developed Requirement R1 of the proposed standard MOD-031-1 Demand Data Reporting. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.7.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand Data Reporting. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.7.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and

consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand Data Reporting. The requirement now states that an entity must provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 part 1.7.3).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The approach is intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk Power System.

This white paper provides a record of how the ad hoc group and industry participants in the informal development decided to address the outstanding directives from FERC Order 693, along with the other components of the results-based standards, such as a risk-based and performance-based standard, along with incorporating the Paragraph 81 initiative.

Appendix A: Entity Participants

The below entities represent a nonexhaustive list of entities that had personnel that participated in the MOD-C 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, 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 C Informal Development				
Austin Energy	Hydro Quebec	MISO	PG&E	PSEG
American Transmission Co.	MEAG Power	NI Source	PJM	XCEL Energy
CenterPoint Energy	Flathead Coop	FERC	PSEG	MidAmerican
ERCOT				
Regional Entities				
FRCC				
MRO				
NPCC				
RFC				
SERC				
SPP				
TRE				
WECC				

Table 2: Presentations and Events	
NERC News	NERC Standards and Compliance Workshop
NERC Operating Committee	Reliability Assessment Subcommittee
NERC Planning Committee	Reliability Assessment Data Working Group
NERC Standards Committee	

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Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1 (the pro forma standard)

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data reporting request.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The pro forma standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The pro forma standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R1	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirement R2	Requirement R2 of the pro forma standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.7.
MOD-017-0.1 R1.1	Requirement R1 part 1.4.1	The pro forma standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.4.2	The pro forma standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.5.1	The pro forma standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.5.2	The pro forma standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	Requirement R1 part 1.6	The pro forma standard will require entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported.
MOD-018-0 R1.2	Requirement R1 part 1.7.1	The pro forma standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirement R2	The pro forma standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.7.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.5.3	The pro forma standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.7.2	The pro forma standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.7.3	The pro forma standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The pro forma standard will require entities to provide the requested data by a certain date.

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Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-031-1
July 3, 2013

Introduction
The NERC Compliance department (Compliance) worked with the MOD C informal ad hoc group (MOD C Group) in a review of pro forma standard MOD-031-1. The purpose of the review is to discuss the requirements of the pro forma standard to obtain an understanding of its intended purpose and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the MOD C 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 will both assist the MOD C Group in further refining the standard and be used to aid in the development of auditor training.

MOD-031-1 Questions

Question 1
In Requirement R2, will the auditor verify 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 sharing of data, the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard.

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 review of the standard enables Compliance to develop training for Compliance Auditors to execute their reviews. However, Compliance does recommend the MOD C Group consider the item(s) noted in the response to the question.

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

Attachment A

B. Requirements and Measures

R1. The Planning Coordinator or Balancing Authority as identified by the Regional Entity in a data request, shall develop and issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include, at a minimum: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities and Distribution Providers that are required to provide the data ("Applicable Entity").

1.2. A schedule detailing the timetable for providing the data. (Note: a minimum of 30-days must be allowed for responding to the request).

1.3. The original data request from the Regional Entity.

1.4. A request for the following actual data[1]:

1.4.1. Integrated hourly demands in megawatts (MW) for the prior year.

1.4.2. Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.

1.4.3. Monthly and annual peak hour weather normalized actual demands in megawatts (MW) for the prior year.

1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in megawatts (MW) for the prior year.

1.5. A request for the following forecast data[1]:

1.5.1. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.

1.5.2. Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

1.5.3. Forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

1.6. A requirement for Applicable Entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported.

1.7. A requirement for Applicable Entities to provide:

1.7.1. The assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.

[1] This could include data reported in the Long Term Reliability Assessment (LTRA) and the EIA 411.

1.7.2. The Demand and energy effects of Interruptible and Direct Control Load Management.How DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.7.3. How the peak load forecast compares to actual load for the prior year with due regard to controllable load[2], temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority as identified by the Regional Entity in its data request, shall have a dated data reporting request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the Planning Coordinator or Balancing Authority or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner) on request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mail or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

R3. The entity identified by the Regional Entity in its data request, shall report the Applicable Entities' data as requested by the Regional Entity within the timeframe specified in the Regional Entity's request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mail or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

[2] For the purpose of this standard, the term "controllable load" shall refer to both interruptible load and direct control load management as referenced in FERC Order 693 Para 1267.

Proposed Timeline for the Project 2010-04 Standard Drafting Team		
Anticipated Date	**Location**	**Event**
July 2013	-	SC Authorizes SAR and Pro Forma Standard for Posting
July 2013	-	Conduct Nominations for Project 2010-04 SDT
July 2013	-	Post SAR and Pro Forma Standard for 45-Day Informal Comment Period
August 2013	-	Conduct Ballot
September 2013	-	45-Day Comment Period and Ballot Closes
September 2013	TBD	MOD C Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Revise as Necessary
September 2013	-	Conduct Recirculation Ballot
November 7, 2013	-	NERC Board of Trustees Adoption
December 31, 2013	-	NERC Files Petition with the Applicable Governmental Authorities

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Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

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

Now Available

A ballot for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) 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. 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, at wendy.muller@nerc.net or at 404-446-2560.

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

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-031-1** 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).*

This project began with an informal development process to address outstanding FERC directives from Order 693 and other issues based on operational lessons learned. The informal effort has produced a pro-forma SAR, pro-forma standard and the associated Implementation Plan that will provide input to the formal standard drafting team. The goal is to present the standard to the NERC Board of Trustees in November 2013.

The data collection/reporting contained in the proposed standard is required for the development of future assessments for resource adequacy and is necessary to outline responsibilities among functional entities to each other. For these reasons, these requirements do not fall under the Paragraph 81 criteria.

Background information, including other supporting documents for this project, can be found on the project page. Please contact either Darrel Richardson, 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 **MOD-031-1** and the associated non-binding poll. 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-031-1: bp-2010-04_MOD-031-1_in@nerc.com
Non-Binding poll for MOD-031-1: bp-2010-04_MOD-031-1_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

A ballot for **MOD-031-1** and non-binding poll 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.

For more information or assistance, please contact Wendy Muller,
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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Ballot and Non-Binding Poll Results

Now Available

A ballot for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) 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: 81.96% Approval: 55.76%	Quorum: 80.35% Supportive Opinions: 58.97%

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.

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Ballot Results	
Ballot Name:	Project 2010-04 MOD-031-1 (MOD C) Ballot 1
Ballot Period:	8/26/2013 - 9/4/2013
Ballot Type:	Initial
Total # Votes:	309
Total Ballot Pool:	377
Quorum:	**81.96 % The Quorum has been reached**
Weighted Segment Vote:	55.76 %
Ballot Results:	**The drafting team will review comments received.**

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	102	1	45	0.6	30	0.4	0	13	14
2 - Segment 2	9	0.8	1	0.1	7	0.7	0	0	1
3 - Segment 3	85	1	42	0.656	22	0.344	1	6	14
4 - Segment 4	29	1	12	0.545	10	0.455	0	1	6
5 - Segment 5	87	1	33	0.673	16	0.327	0	12	26
6 - Segment 6	50	1	24	0.585	17	0.415	0	4	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	2	0.2	1	0.1	0	0	1
9 - Segment 9	3	0.3	2	0.2	1	0.1	0	0	0
10 - Segment 10	8	0.7	4	0.4	3	0.3	0	0	1
Totals	**377**	**7.1**	**165**	**3.959**	**107**	**3.141**	**1**	**36**	**68**

Individual Ballot Pool Results

Segment	**Organization**	**Member**	**Ballot**	**NERC Notes**
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - AEP)

1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
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	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
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	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Negative	COMMENT RECEIVED
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	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	East Kentucky Power Coop.	Amber Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
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		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS (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	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - NIPSCO(MISO) - (MISO)
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED

1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Abstain	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
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	Affirmative	
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	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
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	Abstain	
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		
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	COMMENT RECEIVED
1	San Diego Gas & Electric	Will Speer		

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 - (Seattle City Light)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
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	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	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota		
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	Negative	COMMENT RECEIVED
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	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
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	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		

3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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		
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
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	Affirmative	
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 - (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	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
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	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	

3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
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	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	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	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
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 - (support FMPA 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 - (Seattle City Light)
3	South Carolina Electric & Gas Co.	Hubert C Young		
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	NO COMMENT RECEIVED - (Xcel Energy comments)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
				SUPPORTS

4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	THIRD PARTY COMMENTS - (Support comments from Florida Municipal Power Agency (FMPA))
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
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	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 and Midcontinent Independent Transmission Ssytem Operator (MISO))
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	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
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 - (Seattle City Light)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
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 - (FMPA Comments)
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	
5	Amerenue	Sam Dwyer	Abstain	

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	Affirmative	
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	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
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)
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
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	Abstain	
5	Exelon Nuclear	Mark F Draper	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO, NSRF and ACES)
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		
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	

5	Manitoba Hydro	S N Fernando	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
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	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
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	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
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	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
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 - (Seattle City Light)
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		
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	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
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		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz (AEP))
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
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	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
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	Affirmative	
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	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
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	Affirmative	
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	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	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
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 - (Seattle City Light)
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	Abstain	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
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	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	Negative	COMMENT RECEIVED
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 Results

Project 2010-04 MOD C

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-04 MOD-031-1 (MOD-C) Non-binding Poll
Poll Period:	8/26/2013 - 9/4/2013
Total # Opinions:	274
Total Ballot Pool:	341
Summary Results:	80.35% of those who registered to participate provided an opinion or an abstention; 58.97% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
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	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Negative	COMMENT RECEIVED
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
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		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS (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) - (MISO)
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John Chin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Abstain	

NERC

1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
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	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
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	Abstain	
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		
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	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 - (Seattle City Light)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
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	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	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
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	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
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	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung		
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	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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		

NERC

3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
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 - (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	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
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	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Abstain	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FMPA)
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD Comments provided by Don Schmit.)
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	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	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	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
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 - (Seattle City Light)
3	South Carolina Electric & Gas Co.	Hubert C Young		
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	Affirmative	
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	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	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
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	Abstain	
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	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA & SPP)
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
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
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	Abstain	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
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		
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Abstain	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
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	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
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	Affirmative	
5	PSEG Fossil LLC	Tim Kucey		
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	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
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 - (Seattle City Light)
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		
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	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	WPPI Energy	Steven Leovy		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz (AEP))
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
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	Affirmative	
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	Affirmative	
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 - (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	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Manitoba Hydro	Blair Mukanik	Abstain	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
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	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
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	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 - (Salt River Project)
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 - (Seattle City Light)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	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 - (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. (45 Responses)
Name (28 Responses)
Organization (28 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (45 Responses)
Question 1 (33 Responses)
Question 1 Comments (39 Responses)
Question 2 (34 Responses)
Question 2 Comments (39 Responses)
Question 3 (0 Responses)
Question 3 Comments (39 Responses)

Individual
Thomas Foltz
American Electric Power
No
No
Though R1 provides a prescribed list of “minimum requirements” for the data reporting request, there is no specified limit on the detail or extent of the request. As a result, R1 is extremely open-ended and makes it possible that the data request could not be provided by the timetable specified. In addition, the VSL associated with not meeting the expectations of such a data request is Severe. We disagree with the open-endedness of R1, as well as its sole VSL of Severe. R1 is overly prescriptive and places indirect requirements upon the applicable entity that could be easily established by the Planning Coordinator. R 1.1 – It should be made clear that the list of Functional Entities provided is provided solely as examples, and is not a requirement that all must be included in the data request. There may be circumstances where RE and Planning Coordinator boundaries do not properly align with the manner in which the requirements are written.
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.
Yes
We agree with the approach of combining the standards into one. Specific comments follow. The Implementation Plan Effective Dates section should be modified to indicate that "MOD-001-2 and the modified DMS definitions shall become effective as follows:" The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management have temporary impacts. Conservation would include energy efficiency or building envelope improvements whereas demand management would lead to temporary load reductions or load shifting through price signals, contracts or direct load control. Clarify in the standard. R1 appears to make the PC and BA responsible to develop and issue a data reporting request on the RE formulating such a request. Suggest deleting "as identified by the Regional Entity in a data request" and replace the wording with: And provide to the Regional Entity upon request. Subrequirements 1.4 through 1.7 should be combined into a separate requirement starting with: Each Planning Coordinator or Balancing Authority shall make a request for actual data that shall include, but not be limited to: Regarding part 1.5.3, it asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal capacity as opposed to the total capacity for each season? This part needs clarification as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. Regarding part 1.7, the peak referenced here should be annual peak. There aren't any VSLs for non-compliance with parts 1.4.3 and 1.4.4. Regarding R2, there is a data confidentiality issue if the Applicable Entities are to provide demand forecast data to entities that engage in market activities, such as a LSE. Suggest to qualify R2 by appending "subject to confidentiality requirements" after "on request". The proposed effective date may conflict with Ontario regulatory practice with respect to the effective date of the Standard. Note that there is an approval requirement in Ontario for NERC Reliability Standards. The wording presented in the Effective Dates Section does not reflect this. It is suggested that this conflict be removed by moving the wording: "…or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities" to immediately after "applicable regulatory approval" in the first sentence. In some cases the Standard is overly perscriptive. Variations on the data reporting request shown in the Standard can be used to produce an effective load forecast. To allow for these variations the following changes are recommended: R1. The Planning Coordinator or Balancing Authority, as identified by the Regional Entity in a data request, shall develop and issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include consider, at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.4.3. Monthly or seasonal and annual peak hour weather normalized actual demands in MW for the prior year. For part 1.4.4, it is of note that Load Management can be dispatched for several reasons including audit, economic and reliability. To clarify the

following modification is recommended. 1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW along with reason for deployment for the prior year.
Individual
Kathleen Goodman
ISO New England, Inc
No
Yes
Yes, we agree with the approach of combining the standards into one. However we have several specific comments on changes as listed below.
In some cases the standard is overly perscriptive. Variations on the data reporting request shown in the standard can be used to produce an effective load forecast. To allow for these variations the following changes are recommended: R1. The Planning Coordinator or Balancing Authority, as identified by the Regional Entity in a data request, shall develop and issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include consider, at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.4.3. Monthly or seasonal and annual peak hour weather normalized actual demands in MW for the prior year. For requirement R1.4.4, it is of note that Load Management can be dispatched for several reasons including audit, economic and reliability. To clarify the following modification is recommended. 1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW along with reason for deployment for the prior year.
Individual
Jonathan appelbaum
The United Illuminating Company
No
Yes
This Standard has the Regional Entity initiating the process. 1. The data being requested is not supporting the reliability of the Bulk Electric System because it is not supporting the modeling and planning done by the Planning Coordinators or Transmision Planners. If the data was supporting PC and Planners then those registered entities would initiate the process and utilize the data. 2. The Regional Entity is not in the functional model and should not be assigned a role in a reliability standard. 3. A VRF of Medium is not supported. It should be Low. First, the background discussion on the standard indicates this is a data request and administrative, and second the request is from the Regional Entity which has no role in reliability or running studies

so there can be no adverse impact of reporting bad data.
Individual
Nazra Gladu
Manitoba Hydro
No
Yes
(1) SAR, Brief Description - replace “BPS” with “Bulk Power System (BPS)” since this is the first instance of this term in the document. (2) Purpose - de-capitalize the word “Demand” as it does not appear in the NERC Glossary. Moreover, for clarity, replace the sentence “for assessment and validation of past events” with “to assess and validate past events”. (3) Background - capitalize “demand-side management”, as it appears in the NERC Glossary. (4) R1.7.2 - replace the words “Direct Control Load Management” with their acronym “DCLM”. (5) General Comment - replace “Board of Trustees” with “Board of Trustees’” throughout the applicable documents/standards for consistency with other standards. (6) R1.4, footnote 1 - it is unclear if the requirements will result in additional data request(s) (i.e. in addition to the seasonal and long term reliability assessments and the integrated hourly load request). What is the intent of the SDT?
Individual
John Seelke
Public Service Enterprise Group
Yes
We recommend that the team consider withdrawing the SAR replacing this standard with a Section 1600 data request from each Regional Entity (or collectively by all Regions) where the reasonableness of the requested data and the timing of submitting data will be addressed via stakeholder comments. In their report dated June 2013, the Independent Standards Review Panel, in Appendix E, p. 27, recommended “Retire MODs 16-19 and 21 and gather whatever data NERC needs for assessments and reports through Section 804 of NERC Rules of Procedure.” We prefer a Section 1600 data request instead because it permits stakeholder comments to be considered. However, we believe the issue of which form a data request can be the subject of stakeholder discussion, but the standard should not continue. In any case, we do not believe a standard is necessary for the MOD C standards. Regarding a data request, the team should note that data requests are limited to Registered Entities. The proposed definition for DSM as “The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use” is OK, but the team should recognize that much DSM is provided by aggregators who are NOT Registered Entities. Until those entities are registered, the collection of DSM data will be largely incomplete. (This comment applies even if a standard is developed instead of a data request.)

No
We prefer a data request rather than a SAR.
Individual
Jack Stamper
Clark Public Utilities
No
Yes
R2 currently states “Each Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the Planning Coordinator or Balancing Authority or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner) on request.” Who exactly are these “other entities” and why are the Applicable Entities supposed to provide them this information. Also the "on request" makes it sound like an entity is expecting a request from the PC or the BA but it obviously has a request since it is responding to the request. This “other entity” is way to open ended on who it might be and I do not want to be providing my utility’s historical and forecast load to just any entity that requests it. Why would they need this. If I have provided it to my PC and BA why would other PCs or LSEs or RPs need this information. I do not see any reliability gain by even offering this data to anyone other than the requester (PC and BA). I believe R2 should just state “Each Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the requesting Planning Coordinator or Balancing Authority.” There should be no requirement to provide this information to anyone other than the requesting PC or BA.
Individual
John Bee
Exelon and its' Affiliates
No
Yes
Exelon would recommend enhancing Section A. 4. Applicability, 4.1 Functional Entities, 4.1.5 Load-Serving Entity to read: 4.1.5 Load-Serving Entity listed as an Applicable Entity in R1.1 And 4.1.6 Distribution Provider listed as an Applicable Entity in R1.1
Group
Dominion
Louis Slade

No
Yes
Dominion suggests that R3 and M3 be reworded to clarify the intent. We believe the intent is to provide data within the timeframe provided by the requesting entity. If the SDT agrees that this is the intent, we suggest revising R3 to read " entity Planning Coordinator or Balancing Authority identified by the Regional Entity in its data request, shall report the Applicable Entity's data as requested by the Regional Entity within the timeframe specified in the Regional Entity's request." Requirement 1.7.3 uses the acronym "DSM" which is presumably Demand Side Management. Dominion suggests this be clarified by adding behind Demand Side Management (DSM):. Dominion suggests removing the phrase "or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner)" from R2. We do not believe any entity other that the Planning Coordinator or Balancing Authority should be allowed to make such as request. If the Regional Entity or an adjacent Planning Coordinator or Balancing Authority desires this information, they should have to obtain it by requesting from the Planning Coordinator or Balancing Authority within whose area the demand resides. Dominion suggests that once the standard has received ballot approval, the text boxes be moved appropriately under the relevant requirement rather than being relocated at the end of the standard under the Application Guidelines Section of the Standard.
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Frank Gaffney, Florida Municipal Power Agency
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. The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management have temporary impacts. Conservation would include energy efficiency or building envelope improvements whereas demand management would lead to temporary load reductions or load shifting through price signals, contracts or direct load control. Is this term meant to include both? Please clarify in the standard. b. R.1, 1.5.3 asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal capacity as opposed to the total capacity for each season? This part is unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. c. R.1, 1.7: The peak referenced here should be annual peak. d. R2: There is a data confidentiality issue if the Applicable Entities are to provide demand forecast data to entities that engage in market activities, such as an LSE. Suggest to qualify R2 by appending “subject to confidentiality requirements” after “on request”. e. There does not appear to be any VSLs for non-compliance with Parts 1.4.3 and 1.4.4. Please address the missing VSLs. f. The proposed effective date may conflict with Ontario regulatory practice with respect to the effective date of the standard. Note that there is an approval requirement in Ontario for NERC Reliability Standards. The wording presented in the Effective Dates Section does not reflect this. It is suggested that this conflict be removed by moving the wording: “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities” to immediately after “applicable regulatory approval” the first sentence. The same change also applies to Item (1) under the Effective Dates Section in the Implementation Plan.
Individual
Brett Holland
Kansas City Power & Light
Agree
Florida Municipal Power Agency
Group

Salt River Project
Bob Steiger
No
Yes
Yes, however we have major concerns with how R1 is worded. It is so complicated that it requires the "Rationale for R1" to understand. Simplify this.
The data requested in the MOD is largely redundant to existing reporting requirements within our region, WECC. Maybe this could be handled by a Regional Variance?
Individual
Don Schmit
Nebraska Public Power District
No
Yes
Requirement R 1.7.2 appears to have a typographical error and should have the word “Load” inserted after the word “Interruptible”, such that the requirement would read “The Demand and energy effects of Interruptible Load and Direct Control Load Management.” This correction would make the use of the term “Interruptible Load” consistent throughout the proposed standard. In the VSLs for R1 a PC or BA is required to develop a data reporting procedure yet the development of this procedure is not included in the requirement. We suggest replacing the phrase ‘…developed a data reporting procedure…’ with ‘…issued a data reporting request…’. Also in the High VSL for R1, insert ‘Part’ in front of 1.4.2. In the Severe VSL for R2, replace ‘developed’ with ‘issued’. In fact, we would suggest that the Severe VSLs for R2 be graduated across the spectrum of possible VSLs to make it consistent and parallel with R1.
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes
The SDT and NERC are requested to place a high priority on reviewing MOD-020-0.
Yes
R1.1 The SDT should look at adding Resource Planner to the applicable entities. 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.
Group
seattle city light
paul haase
Seattle City Light appreciates the efforts of the Standards Drafting Team to consolidate numerous data collection Standards into one more-consistent approach. If it were simply a consolidation, Seattle would support the draft. However, draft MOD-031-1 expands the data to be collected and the information required about the process. MOD-031-1 is most unclear about how NERC would benefit from collecting all this data, yet it comes at significant cost. Data collection creates significant reporting burden and labor requirements. The only justification provided is for evaluating what happened during significant events. This is a poor argument from a cost-effectiveness standpoint, because such significant events are infrequent. Instead, Seattle asks that the draft be revised to require submission of data from the affected parties after these infrequent events occur, rather than placing the unnecessary administrative burdens on everyone, regardless whether or not an event occurs. Some secific elements of draft MOD-031-1 that expand the reporting burden on entities include (i) Requirement 1.7.1. "The assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts." Seattle finds this requirement to be ill-defined, potentially open-ended, and could be quite onerous because of the great many assumptions and forecasts that are components to a system load forecast, even for a relatively small system and (ii) Requirement 1.7.4. "How the peak load forecast compares to actual load for the prior year with due regard to controllable load, temperature and humidity variations." Seattle finds this new requirement to be of limited value. As most load forecasters know, different utilities with different service areas have widely varying load characteristics and driving factors. The request seems to be largely aimed at providing NERC sufficient data to do their own service-area level load forecasts for the utilities. Even if NERC or a regional entity is armed with this uniform information request, it is unlikely to be of much use, because different economic growth assumptions are applied, as are differences in population growth, the nature of specific new loads, unique weather patterns, and much more. Seattle recommends that both new requirement be deleted.
No
In general Seattle supports the consolidation of prior data collection MOD standards, but does not support the expansion of the data collection requirements. See comments to Question 1, above.
Seattle is concerned about the redundancy between proposed MOD-031-1 and existing data collection process within our region, WECC. We find the WECC already requires most of the identified information from Seattle City Light for the purpose of its winter and summer (reliability) assessments. The currently-requested data by WECC includes: 1.4.1. Integrated hourly demands in megawatts (MW) for the prior year.] I believe we report this now, but am not certain, since I have not been part of that data collection. 1.4.2. Monthly and annual peak

hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. 1.4.3. Monthly and annual peak hour weather normalized actual demands in MW for the prior year. 1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW for the prior year. 1.5.1. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. 1.5.2. Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future. 1.5.3. Forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions. 1.6. A requirement for Applicable Entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported. 1.7. A requirement for Applicable Entities to provide: 1.7.2. The Demand and energy effects of Interruptible and Direct Control Load Management. 1.7.3. How DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load. which represents all the substantive data required by MOD-031-1 with the exception of 1.7.1 and 1.7.4, both of which are new types of data not previously requested (and recommended to be deleted by Seattle). Finally, Seattle supports the comments of Florida Municipal Power Authority (FPMA) regarding separation of short-term load forecasting from long-term load forecasting, and its comments about the expected relative accuracies. Even the methodologies employed for these two types of forecasts are quite different.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Agree
Florida Municipal Power Agency (FMPA)
Group
JEA
Thomas McElhinney
No
No
The requirements of this standard are all about data collection and should be eliminated in accordance with the paragraph 81 initiative.
Individual
Diane Barney
New York State Department 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.
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC Planning Standards Subcommittee
Individual
Silvia Parada Mitchell
NextEra Energy
No
MOD-031-1 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 advance MOD-031-1. If the SDT believes this data is importanr, it should be accomplished via a Section 1600 data request, as the Misoperations SDT determined for Misoperations data.
Group
Electric Power Supply Association
Jack Cashin
Yes
EPSA believes that simultaneous processing of the SAR and the standard, as was done in this instance puts them at cross-purpose with one another. This risks a situation where if a SAR needs changes, stakeholder comments on standard will be based on a defective SAR that needs work and becomes an inefficient use of stakeholder resources. The SAR scope for proposed MOD-031-1 has not considered all the aspects that can ensure that the Standard will reach a steady state. Since its issuance in June of 2013, NERC and Stakeholders have recognized that the “Standards Independent Experts Review Project” provides a global assessment of Standards including the “MOD C” standards inclusive of MOD-031-1. The Independent Experts recommend that requirements that are part of VAR-002-2 are duplicative and covered under

other standards or covered by tariff requirements. Additionally, the Comment form intones that because MOD-031-1 is a “pure data reporting standard” that it would be a candidate for retirement were it not for resource adequacy reliability purpose of the standard. EPSA believes that resource adequacy is not part of the ERO’s reliability jurisdiction and therefore should not be the reason for the scope of the SAR. To avoid duplication or conflating reliability and market issues the SAR scope would benefit from including the recommendations of the Independent Experts in the current VAR-002-2 project. This will avoid expending resources on the Independent Experts recommendations in the future.
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst offers the following comment for consideration: 1. MOD C Whitepaper – ReliabilityFirst recommends highlighting all new requirements which are included within the draft standard (based on FERC Directives) in order to help entities understand that these are new requirements in which they will need to comply. Specifically, one FERC directive was to provide temperature and humidity data so actual data can be weather adjusted for comparison to the forecasts. While this data may be available from many entities, ReliabilityFirst does not believe every entity with a demand forecast has this information. ReliabilityFirst believes these types of new requirements should be more acknowledged or noticed to the industry.
No
ReliabilityFirst offers the following comment for consideration: 1. FERC Directive (order 693, paragraph 1298) not addressed – ReliabilityFirst does not believe the FERC Directive on standardizing principles for reporting and validation of DSM information (order 693 paragraph 1298) has been addressed. The FERC directive asks for standardization of DSM reporting and program verification “… and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information”. The response in the MOD C Whitepaper talks about requiring an explanation “...of how DSM is forecasted and adjusted for errors (Requirement R1 part 1.7.3)” Explaining forecast methods and adjustments is not the same as standardizing reporting and verification requirements. ReliabilityFirst believes the SDT should revisit this requirement and ensure it is addressing the intent of the FERC Directive associated with Order 693 paragraph 1298.
ReliabilityFirst offers the following comments for consideration: 1. Requirement R1, Parts 1.3 through 1.5 – ReliabilityFirst believes the standard should be less prescriptive regarding which data elements should be reported in the data request (i.e., the Planning Coordinator or Balancing Authority should determine what data they need and place it within the request). Specific information is already spelled out in the LTRA data request from NERC. The NERC data

request collects demand data (and other data) for assessments and to provide a response to DOE for the EIA-411. Since NERC lists the specific data items in its data request, by not being specific or prescriptive in the standard, NERC can change or modify the requested data as needed to satisfy DOE reporting (EIA-411) or to accommodate any future assessment needs. 2. Requirement R1, Part 1.6 – ReliabilityFirst believes there is no reliability benefit to including Requirement R1, Part 1.6 in the standard. ReliabilityFirst believes this is already done via the NERC RAS assessment process and is administratively over burdensome. Furthermore, if the SDT believes it is a necessary sub-part, ReliabilityFirst notes that Requirement R1, Part 1.6 was included to cover requirement 1.1 from MOD-018-0 in the original standard. ReliabilityFirst does not believe the wording in Requirement R1, Part 1.6 has the same intent as the original standard. ReliabilityFirst offers the following for consideration: “A requirement for Applicable Entities to identify non-registered entities within their footprint if the non-registered entity demand data is included in the submitted data.
Group
ISO/RTO Standards Review Committee
Greg Campoli
Specific comments: The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management have temporary impacts. Conservation would include energy efficiency or building envelope improvements whereas demand management would lead to temporary load reductions or load shifting through price signals, contracts or direct load control. Is this term meant to include both? Please clarify in the standard. MOD-031-1, R1.5.3 asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal capacity as opposed to the total capacity for each season? This part is unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. MOD-031-1 R1.7. requires: “ A requirement for Applicable Entities to provide: 1.7.1. The assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts. 1.7.2. The Demand and energy effects of Interruptible and Direct Control Load Management. 1.7.3. How DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load. 1.7.4. How the peak load forecast compares to actual load for the prior year with due regard to controllable load2, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. 1.7.1 seems to be a fill-in-the-blank requirement 1.7.2 is usually a guess as opposed to a fact. The quantitative effects of any one thing are dependent on other assumptions. To say “DR did X”, requires the assessor to assume the load and generation quantities (did consumer load go down, did generation go up, did DR make up the difference, is the frequency the same??????) 1.7.3 seems to be a fill-in-the-blank requirement 1.7.4 seems questionable for large systems.

What is a large area's temperature and Humidity at any one time? How will "future" adjustments be made? Does that mean if the entity guesses that it will adjust the load forecast in one way, but next year it does not use that assumption, is the entity in violation? R2: There is a data confidentiality issue if the Applicable Entities are to provide demand forecast data to entities that engage in market activities, such as an LSE. Suggest to qualify R2 by appending "subject to confidentiality requirements" after "on request". There does not appear to be any VSLs for non-compliance with Parts 1.4.3 and 1.4.4. Please address the missing VSLs.
Group
SPP Standards Review Group
Robert Rhodes
No
Yes
We would like to thank the ad hoc team for their efforts in developing a proposal for consolidating several of the MOD standards into a more concise package. The definition of Demand-Side Management is to be changed per the draft standard. While we don't have any issues with the proposed changes, the spelling of the term should be consistent. Is the hyphen between Demand and Side supposed to be there or not? In Section 5. Background, the Bulk Power System is referenced. The reference should be to the Bulk Electric System. Also, at the top of page 2 Demand-Side Management needs to be capitalized. These items also need to be addressed in the whitepaper. In the VSLs for R1 a PC or BA is required to develop a data reporting procedure yet the development of this procedure is not included in the requirement. We suggest replacing the phrase '…developed a data reporting procedure…' with '…issued a data reporting request…'. Also in the High VSL for R1, insert 'Part' in front of 1.4.2. In the Severe VSL for R2, replace 'developed' with 'issued'. In fact, we would suggest that the Severe VSLs for R2 be graduated across the spectrum of possible VSLs to make it consistent and parallel with R1. "Load' is omitted in R1.7.2. It should be inserted following Interruptible in the requirement.
Group
PacifiCorp
Kelly Cumiskey
No
No
The term Demand Side Management has been defined as, "All activites or programs undertaken by any applicable entity to influence the amount or timing of electricity they use."

PacifiCorp believes this definition is ambiguous and lacks criteria for measuring. Moreover, by implementing this broad based definition for demand side management, PacifiCorp is concerned that it will lead to varied interpretation and a lack of uniformity across utilities. R 1.4.4 and R 1.7.2: It's unclear how these two requirements differ except for 1.7.2 requesting the energy impacts. In addition, given that interruptible and direct load control is typically exercised only a few hours annually and in some cases the energy is taken back at a different hour following a curtailment event, it is unclear why this information would be meaningful in load forecasting. PacifiCorp believes that requesting the energy effects without a clear methodology for creating the energy estimates will lead to varied interpretation and a lack of uniformity across utilities. R 1.7.4: PacifiCorp does not agree with the requirement to compare actual loads for the prior year and how the "assumptions and methods for future forecasts were adjusted." The requirement is vague, does not define what expectations are associated with the assumptions (or methods that may change), and will provide no additional clarity to the forecast beyond the explicit change associated with simply adding the additional year of actual values into the calculation. As such, PacifiCorp suggests it be removed from the requirement.
Group
Bonneville Power Administration
Jamison Dye
No
Yes
BPA believes that these requirements gather the data from the previous MODs which are critical to effective planning. They appear to be streamlined and ask for the critical information. BPA also believes there are some differences that are not as effective and recommends that the Drafting Team revise MOD-031 in the following areas to resolve these concerns: 1) MOD-031 R1 Indicates that these activities should be completed after receiving a data request from the Regional Entity. Since these MODs are most effective if completed annually, BPA recommends that this MOD have an embedded start data such as, "the MOD should be completed annually starting after March 1 of each year". Any date to gather the data would work however a late winter or spring date would give receiving entities useful data to help with their within year planning as it is beneficial to the planning entities if the gathered data is done on a consistent planning schedule. Having the most up to date forecasts for this submittal is also best and having a consistent date would facilitate movement by the data providers to plan annually at a consistent time to meet this data need. Further, as written the MOD requires the Regional Entity to initiate the data gathering step. If the Regional Entity becomes busy with other activities this event may not be started with sufficient time to facilitate planning. This MOD further solidifies this notice requirement in MOD R1. 1.3 requiring the Planning Coordinator or Balancing Authority to provide additional unnecessary paperwork. If the annual date were included in the MOD-031 text, the paperwork required in MOD-031 R1. 1.2 could

just reference the MOD-031 starting date in the text and requirement MOD-031 R1. 1.3 would not be needed at all. 2) In MOD-031 R1. 1.4.3 a request is made for the weather normalized actual demands in MW. BPA believes that not all LSEs have the capability to do weather normalization of actual demands. Further there are numerous methods to normalize with differing results, making the data less usable. BPA recommends having the submitting entities provide the hourly weather that would be used for normalization along with the hourly integrated demands. This would more fully allow planning practices to address analysis and risks associated with weather uncertainty as need.
Group
Duke Energy
Colby Bellville
Yes
Duke Energy questions the need to include BA(s) in the SAR and pro-forma standard. The MOD standards identified in the MOD-C project for consolidation do not include the BA as an applicable entity. Also, all three requirements in the pro-forma standard list a time horizon of “Long Term Planning.” Duke Energy does not feel that “Long Term Planning Horizon” is applicable to a BA.
Yes
While Duke Energy agrees with the approach of consolidating the MOD standards applicable to this project due to overlaps in the standards, we do not agree with placing the PC or BA in charge of collecting and submitting data as is written in the proposed standard. In the currently effective MOD C standards, Applicable Entities are required to report the data to either the ERO or RRO. The proposed MOD-031 would put the ownership on the PC or BA to collect the data from various LSEs and DPs within their Planning Authority Area, and then report the data to the RRO. We believe this places an unnecessary compliance burden on the PC or BA by having them gather and submit data that is already being submitted by the applicable entities. Duke Energy supports the recommendation made in the report submitted by the Independent Industry Experts, wherein they suggested that MODs 16-19 and 21 should be retired, and that the gathering of whatever data NERC needs for assessments and reports be done through Section 804 of the NERC Rules of Procedure. (See Appendix E of the Independent Expert Report) Also, the Purpose of this standard should be changed to “ To ensure that actual and forcasted Demand data necessary for reliability assessments, validation of past events, and in support of future system assessments are reported in a timely manner.”
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 to question 1
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
NM is a summer peaking entity serving loads in WECC. PNM disagrees with the language in R1.4.3. as it requires not only the annual peak demand, but the monthly peak demand to be weather normalized. Currently, PNM spends considerable time and effort to weather normalize its demand forecasts for the annual peak but does not employ that methodology for the monthly demands when they are away from the summer peak timeframe, i.e. shoulder periods. PNM requests that the standard allow flexibility in the monthly demand forecasts such that weather normalization is not explicitly required. PNM agrees with keeping the annual weather normalization in the requirement language.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No

Yes
ATC recommends the following changes be made to the draft Standard MOD-031-1: 1. Modify Requirements R1.5.2 and R1.5.3 text by adding the word “Annual” at the start of both sub-requirements below: a. R1.5.2 would read: “Annual peak hour forecast demand (summer and winter) in MW…” b. R1.5.3 would read “Annual forecasts of Interruptible Load and Direct Control Load Management (DLCM)…” to make it closer to the requirement within MOD-016, and more clearly specifies the data of interest. 2. Modify Requirement R2 text to read “…Balancing Authority or any other NERC registered entity (such as Load Serving Entity, Transmission Planner or Resource Planner)…”. The first text change eliminates confusion about “any other entity” and the second change includes Transmission Planning in the specified list of data receivers and removes the redundant identification of Planning Coordinator. 3. Modify Requirement R3 text to read, “The entity identified by the Regional Entity, either Planning Coordinator or Balancing Authority, in its data request,…” to better match the text in MOD-031-1 R1. This change improves the consistency of the pro forma standard text. 4. ATC believes there is a lack of requirements accounting for non-entity contribution to load. This concern was addressed in MOD-018 and has not been included in MOD-031-1 (non-entities could be explicitly included in MOD-031-1 R1.6).
Individual
Scott Langston
City of Tallahassee
The current draft standard contains both vague and duplicative requirements and potentially obligates Applicable Entities to perform analyses that are beyond the scope of current acceptable practice and do not enhance the reliability of the BPS.
Individual
Catherine Wesley
PJM Interconnection
No
Yes
In addition to signing onto the SRC’s comments for this project, PJM is submitting the following additional comments: • The definition of “Demand Side Management” must be more explicit. Does it include emergency load management and economic load response? Does it include only load response programs that are under the operational control of the reporting entity? In

the case of an ISO/RTO, would this mean reporting only demand response that is active in the wholesale market? (This would be consistent with NERC DADS requirements.) • Requirement R.1.4.3 requires production of monthly weather-normalized peaks for the prior year. Many entities determine weather-normalized values on a seasonal, not monthly, basis. PJM recommends the frequency remain on a seasonal basis consistent with present practices. • Requirement R.1.4.4 calls for reporting “deployed” load management for the prior year. “Deployed” should be clearly defined. (Is it the the nominal amount called upon, the actual amount delivered, etc.?) • Requirement R.1.7.2 calls for providing the energy effects of forecasted load management. Most entities determine the peak impacts, not the energy effects, of forecasted load management for reliability planning purposes. Additionally, energy effects are used for production cost or economic evaluation purposes. They generally do not address a reliability concern which is the case with peak effects on the system. PJM does not support energy effect data being added to the standard.
Individual
Bill Fowler
City of Tallahassee
The current draft standard contains both vague and duplicative requirements and potentially obligates Applicable Entities to perform analyses that are beyond the scope of current acceptable practice and do not enhance the reliability of the BPS
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Agree
IRC Standards Review Committee
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PSS
Group
ACES Standards Collaborators
Ben Engelby
Yes
(1) We are concerned that the informal development process that was originally contemplated has gone off course. The original plan 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. The informal development team should not have been appointed as the formal standard drafting team without soliciting nominations, as this creates the perception of NERC not following the standards development process. The informal development process should not circumvent the NERC Rules of Procedure. (2) 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 that stakeholders have no opportunity to influence the scope contained in the SAR contrary to the standards development process. It seems unnecessary to comment on the SAR at this point because it appears that it was drafted in tandem with the pro forma standard. 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. (3) We are also concerned that the standards process manual was not followed correctly regarding the selection of the drafting team. The nomination period began after the draft standard was posted, which clearly shows the ad hoc team developed the draft standard instead of satisfying the acitivities it was charged with by vetting the issues of the MOD standards with industry. The initial draft standadrd should be the work of the appointed standards drafting team. We doubt that there was sufficient time for the new drafting team members to thoroughly review and agree with the language in the initial posting. The method of developing the initial draft should comply with the NERC Rules of Procedure and we are concerned that a bad precedent is being set.
No
The unofficial comment form did not include a field for comments for question 2. Our comments on MOD-031-1 are located in question 3.
(1) We recommend that the drafting team refer to the industry experts report titled “Standards Independent Experts Review Project: An Independent Review by Industry Experts,” which contains recommendations to remove several requirements that impact the MOD C project. The requirements applicable to the MOD C project include MOD-016 R1, R2, R3; MOD-017 R1; MOD-018 R1 and R2; MOD-019 R1; and MOD-021 R1, R2, and R3. We strongly recommend that the drafting team review these recommendations and remove all requirements in the draft standard that have carried over from the above referenced requirements. According to the expert report, these requirements do not belong in a reliability standard because they are data collection and retention actions, and NERC could “gather whatever data NERC needs for assessments and reports through Section 804 of NERC Rules of Procedure.” In light of these recent developments, we cannot support this standard until these changes are made. (2) Several aspects of this standard meets Paragraph 81 criteria. The P81 criteria states: Section B2, Data Collection/Data Retention: These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes. Further, Section B4, Reporting: if a Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity, then this requirement should be retired under P81. 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. (3) In addition to the P81 requirements, data collection belongs under the Rules of Procedure. These data collection activities should not be a part of a reliability standard. TADS is an example of a standing 1600 data request must be complied with periodically. (4) The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. We ask that the drafting team revise the definition for clarity. (5) Regarding MOD-031-1 R1, the use of the terms: “data request,” “data reporting request,” and “data request issued by the Region” can lead to confusion. This appears to be an attempt to bypass Section 1600. Essentially, the requirement says NERC can issue a request and it now does not have to go through the section 1600 data request. We suggest rewriting the requirement to make the intent clear. (6) Requirement R1. Similar to the other MOD projects, we recommend revising the requirements to include an attachment that details the specific data. This level of granularity is confusing and unneeded. (7) Requirement R1, part 1.5.3 asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal levels as opposed to the total levels for each season? It is unclear as to what exactly the Planning Coordinator or Balancing Authority needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. (8) Requirement R2. This requirement meets Paragraph 81 criteria. Specifically, The P81 criteria states: Section B2, Data Collection/Data Retention: These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes. Further, Section B4, Reporting: if a Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity, then this requirement should be retired under P81. 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. (9) We do not see the need for Requirement R3. Regional entities have several tools to request data, as outlined in the NERC Rules of Procedure. It is unnecessary to include a requirement that states an entity must provide data to its Region. The Region will have other methods to collect the data, which makes this requirement unnecessary. (10) In addition to the comments on the requirements, we recommend the drafting team develop an RSAW or other compliance guidance to better understand how the proposed standard will be assessed in an audit. (11) Thank you for the opportunity to comment.
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
Yes

The current draft standard contains both vague and duplicative requirements and potentially obligates Registered Entities to perform analyses that are beyond the scope of current acceptable practice and do not enhance the reliability of the BPS.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Yes
I do not feel there is a compelling reliability need for this standard. There is sufficent authority in existing standards and other regulations outside the standards process for reliable data gathering and there was no demonstration of an actual reliability need that required a standard.
No
the existing standards are fine, in my opinion.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
As considered in the background information section of the Unofficial Comment Form, we believe that MOD-016 through MOD-019, and MOD-021 should be retired based on criteria established in the NERC “Paragraph 81 Project Technical White Paper” (dated December 20, 2012). Within the background information of the Unofficial Comment Form, it is stated that “the data being collected has a reliability purpose in the development of future assessments for resource adequacy”. However, there are currently no reliability standards that address resource adequacy, and the future assessments that the data is used for is not a product of a user, owner, or operator of the bulk power system. We believe this data reporting activity is more appropriately addressed under the NERC Rules of Procedure.
As stated under question number 1, we believe the MOD-016 through MOD-019, and MOD-021 standards should be retired without a successor. If there is to be a successor, we agree with the approach to consolidate into a single standard. We submit the following comments on MOD-031-1 should it go forward: The standard’s title and purpose statement indicate that demand data is the only information of interest, however the requirements include references to energy data and controllable Demand Side Management (Interruptible Load and Direct Control Load Management). We suggest that references to energy data and controllable DSM be removed from the standard, or that the title and purpose of the standard be revised to capture the reliability related need for this data. R1 We suggest this requirement end after

R1.1.3. R1.1.4 and R1.1.5 and their sub-requirements simply try to capture the types of “demand data” that might be requested by the Regional Entity. Since R1 contains the phrase “at a minimum”, a literal interpretation would suggest that every data request issued by the PC or BA to an Applicable Entity must include R1.1.4 through R1.1.7 and their associated sub-requirements. As an alternative, R1.1.3 could be expanded to state “The types of data the Regional Entity may request includes, but is not limited to: “ followed by a bulleted list. We believe the PC and BA should already know the answer to R1.1.6, and not have to rely on the Applicable Entities for this information. For R1.1.7, what is the expected format of the response - data or narrative? How will the Regional Entity and NERC use this information in the context of resource adequacy assessments? For R1.1.2 - The Applicable Entities must be given a minimum of 30 days to respond to a request once it is received from the PC or BA. That being the case, we suggest that similar consideration for timing be factored into R3. The PC or BA must be allowed time to process the data it receives from Applicable Entities before passing it on to the Regional Entity (it has to be in excess of 30 days given the R1.1.2 language). For R1.1.4.1.4.1 - It has been our experience that integrated hourly demands for the prior year are collected through the FERC Form 714 and are not submitted through the Regional Entity. For R3 - We believe the first “entity” referenced in the requirement is intended to be either a PC or BA, based on R1. If that is the case, it would be clearer to confirm it in a parenthetical. “The entity (Planning Coordinator or Balancing Authority) identified by the Regional Entity....”.
Individual
Richard Vine
California Independent System Operator
No
Yes
Section 5 – Background – add the following sentence to the beginning of the first paragraph: To ensure that the purpose of this standard may be carried out various forms of historical and forecast demand and energy data and information must be available to the parties that perform the studies and assessments needed to ensure the adequacy of the Bulk Power System (BPS) and to be able to validate past events. In the last paragraph of 5. Background, revise the text from: The collection of demand projections requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhance the reliability of the BPS. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. To the following text: The collection of demand

projections requires various levels of coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhances the reliability of the BPS. Consistent documenting and information sharing activities helps to facilitate will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. R1.4.2 Comment: Reporting tools can easily be used to glean the annual from the monthly. No need to request both. R1.4.2 current language: Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. R1.4.2 proposed language: Monthly peak hour actual demands in MW and monthly and annual Net Energy for Load in gigawatthours (GWh) for the prior year. R1.4.3 Comment: What is the proposed use of weather normalized actual demand? This data request will create concerns and many questions for requesting entity. It is likely that a significant number of entities do not weather normalize their actual demand. For the entities that do not perform a weather normalization process, and even for those who already do, one of three things will occur related to this requirement; (1) they will do it accurately, (2) they will do it inaccurately, or (3) they will want guidance on how to perform weather normalization. Related to seeking guidance, entities will seek that guidance from the requesting entity on how to do it – out of either lack of experience or concern for being at risk of violating the requirement – and the requesting entity will not be in a position to provide that guidance. Consequently, this requirement will need some level of definitions and methodology provided to the Functional Entities, such as the minimum number of years of weather data needed to calculate the weather normalized demand, what are acceptable methodologies to utilize, and what to do if the entity does not have a sufficient database of historical weather. Unless NERC can provide a compelling reason for this requirement the CAISO strongly recommends deleting R1.4.3. R1.4.4 comment: Deployed DCLM does not always equal the amount realized in California IOU programs. Realized is more important than deployed for reconstructing actual unaffected demand, and at a minimum realized should be collected. This should be defined as “dispatchable” DCLM and stipulate that it does not include “load modifiers” such as energy efficiency. R1.4.4 current language: Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW for the prior year. R1.4.4 proposed language: Monthly peak hour deployed Interruptible Load and Direct Control Load Management in MW, and the MW amount of realized Interruptible Load and Direct Control Load Management based on the amount deployed, for the prior year. R1.5.1 comment: Is there a reason not to collect monthly forecast peak demand for ten years? Recommend incorporating 1.5.2 into 1.5.1. R1.5.1 current language: Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. R1.5.1 proposed language: Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for ten years into the future. R1.5.2 comment: See comment for R1.5.1 above to incorporate into R1.5.1, delete R1.5.2. R1.7.2 comment: For the IOUs in California the demand effects of Interruptible and Direct Control Load Management programs

are very preliminary until studies are completed and this information is provided to the CPUC in a report on April 1 of each year. Consequently only estimated data, which historically has been inaccurate, is available before April 1 and the final data would only be available to the Regional Entity by May 1 at the earliest. As a final point, many municipal systems have small programs, some totaling less than 1 MW. The CAISO recommends that a 10 MW minimum threshold for reporting this data be added to this requirement. R1.7.2 current language: The Demand and energy effects of Interruptible and Direct Control Load Management. R1.7.2 proposed language: The Demand and energy effects of Interruptible and Direct Control Load Management at such time as the information becomes available from the Applicable Entity. Applicable Entities with less than 10 MW of combined Interruptible and Direct Control Load Management programs are exempt from this requirement. R1.7.4 current language: How the peak load forecast compares to actual load for the prior year with due regard to controllable load2, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. R1.7.4 proposed language: A brief discussion on how the peak load forecast compares to the actual load for the prior year. In the discussion with due regard shall be given to controllable load2, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. Compliance section 1.2 Evidence Retention Revise second paragraph Current language: The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3, 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. Proposed language: The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3, since the last audit, regardless of whether this Standard was part of the scope of the last audit or not, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. Comment: Without this an entity that does not have this Standard as part of the scope for multiple audit cycles would be required to maintain evidence for many years.
Group
MRO NERC Standards Review Forum
Russel Mountjoy
No
Yes
Comments: The NSRF agrees with the consolidation of Requirements into one Standard with the following recopmmendation to be considered by the SDT. R1. 1.4.3 and 1.4.4: Please clarify the need for “annual” actual peak load and weather normalized “annual” peak load if they are already asking for the 12 monthly numbers? Clarification is needed if there is a difference between the highest of the 12 monthly and the annual peak in this context? Is the highest load equal to the annual peak? Please clarify. R1. 1.4.3”Monthly and annual peak hour weather

normalized actual demands in MW for the prior year." Weather normalization seems to be more art than science especially when is comes to monthly peak demands. Different months will require different methodologies with shoulder months being particularly challenging. Recommend I would suggest to focus on only the summer peak and winter peak. This will simplify the process, limit the modeling to two methodologies and focus on the peak periods of the two key season peaks. Suggested Language Change: "Summer season (June-Sept) and winter season (Jan-May; Oct-Dec) peak hour weather normalized actual demands in MW for the prior year". It is recommended that the above language be applied to R1.7.4.
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
No
Yes
In general, CenterPoint Energy agrees with the approach to consolidate the "MOD C" standards. Specfic comments are as follows: (1) CenterPoint Energy finds the introductory language in Requirement R1 to be unnecessarily confusing. The basic premise seems to be the Regional Entity will issue a data request to a Planning Coordinator or Balancing Authority who, in turn, issues a data request to Applicable Entities. Assuming this is correct, CenterPoint Energy suggests the use of the following language "Each Planning Coordinator or Balancing Authority identified in a data request by the Regional Entity shall develop and issue an associated data request to Applicable Entities (as defined in Part 1.1 below). The Planning Coordinator's or Balancing Authority's data request shall include, at a minimum:" Note, other references to "data reporting request" would need to be changed to "data request" if the SDT adopts the suggested language. (2) The use of the phrase "or any other entity" in Requirement R2 is open-ended. CenterPoint Energy asks the SDT to use language that more specifically speaks to the intent. CenterPoint Energy suggests the following language: "or affected Load Serving Entities, Planning Coordinators or Resource Planners on request." (3) The VSL for R1 does not include references to Parts 1.4.3 or 1.4.4. Additionally, for completeness, the Severe VSL for R1 (third paragraph) should say "… but failed to address four or more of the items listed in Requireiment R1, Part 1.6 or Part 1.7.1 through Part 1.7.4" instead of "… but failed to address any of the items." (4) In R1.5.2. requiring requested forecast data "…for ten years into the future" is burdensome and unnecessary. CenterPoint Energy recommends retaining the current language in place for MOD-017 R1.4 "…for at least five years and up to ten years into the future, as requested." Thank you for your consideration of these comments.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery

Yes
AECI certainly hopes our BES reliability is not truely dependent upon the accuracy of overall BES load-forecasting, because this has been the historical Holy Grail of our Industry for at least the last thirty years.
No
While responsible entities produce load-forecasts necessary to their business and resource-reliability purposes, this standard requires our company to assume compliance risks far in excess of what AECI believes to be acceptable trade-off value to BES reliability. Specifically: R1.4.3, R1.4.4, R1.5.3, R1.6, R1.7.2, R1.7.3, R1.7.4, all carry payloads of compliance burden that would drive AECI to incur additional expenses of questionable value, particularly for a system of our size within the Eastern Interconnection footprint.
See AECI's response to Question 2. AECI understands the problems associated with load-forecasting, but if the ERO or designees want to get to this data, then our RCs already should have sufficient net-Generation and net-Interchange values for calculating instantaneous load data within their footprint. Further, this is a complex problem where experience has often indicated that attention to greater granularity or detail, can produce greater aggregate error.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
Yes
(1) Austin Energy (AE) finds the introductory language in Requirement R1 unnecessarily confusing. The basic premise seems to be the Regional Entity will issue a data request to a Planning Coordinator or Balancing Authority who, in turn, issues a data request to Applicable Entities. Assuming this is correct, AE suggests the use of the following language “Each Planning Coordinator or Balancing Authority identified in a data request by the Regional Entity shall develop and issue an associated data request to Applicable Entities (as defined in Part 1.1 below). The Planning Coordinator’s or Balancing Authority’s data request shall include, at a minimum:” Note, other references to “data reporting request” would need to be changed to “data request” if the SDT adopts the suggested language. (2) AE requests the SDT change Requirement R1.5.2 from “…for ten years into the future” to match the current requirement in MOD-017 which calls for “…at least five years and up to ten years into the future, as requested.” (3) The use of the phrase “or any other entity” in Requirement R2 is open-ended. AE asks the SDT to use language that more specifically speaks to the intent. AE suggests the following language: “or affected Load Serving Entities, Planning Coordinators or Resource Planners on request.” (4) The VSL for R1 does not include references to Parts 1.4.3 or 1.4.4. Additionally, for completeness, the Severe VSL for R1 (third paragraph) should say “… but failed to address four or more of the items listed in Requireiment R1, Part 1.6 or Part 1.7.1 through

Part 1.7.4” instead of “… but failed to address any of the items.”

Additional comment received from MRO regarding Q3:

R1-MRO does not support the responsibilities identified towards the Regional Entity, Regional Entities are not owners, users or operators of the BES. This requirement should be the responsibility of the Planning Coordinator and any Balancing Authority identified by the Planning Coordinator to supply the data.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

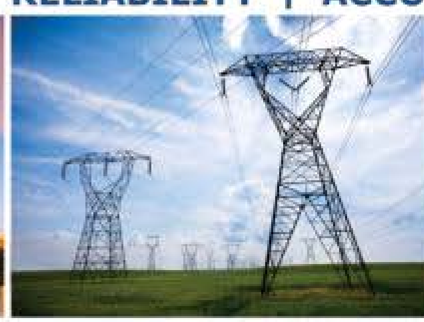
Consideration of Comments Summary

Project 2010-04 Demand Data

October 8, 2013

RELIABILITY | ACCOUNTABILITY



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Introduction

The Project 2010-04 standard drafting team (SDT) thanks all commenters who submitted comments on MOD-031-1. The standard was posted for a 45-day formal comment period from July 24, 2013 through September 4, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 45 sets of responses, including comments from approximately 110 different people from approximately 100 companies representing 8 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 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

Purpose

The MOD-031-1 SDT appreciates industry's comments on the MOD-031-1 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if an additonal comment period and ballot are needed. The following pages are a summary of the comments received and how the SDT addressed them. If a specific comment was not addressed in the summary of comments, please contact the NERC standards developer to discuss.

Process

Several commenters expressed concern that the simultaneous posting of the Standards Authorization Request (SAR) and the proposed standard for initial comment and ballot was outside the scope of the Standards Process Manual (SPM). The SDT notes that although this action was authorized by the NERC Standards Committee, NERC received an appeal of the SPM, which has been resolved. The SDT notes the process issue is outside the purview of the SDT.

ROP Section 800/1600 Data Request

Several commenters stated that the exising MOD C standards (MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, MOD-020-0 and MOD-021-1) should be retired. Commenters argued that the data could be collected by NERC and the Regional Entities through data requests issued pursuant to Section 800 or Section 1600 of NERC's Rules of Procedure. The SDT concluded that a standard was necessary for two reasons.
First, the standard provides an efficient and enforceable mechanism for NERC and the Regional Entities to obtain demand data from all relevant registered entities across the entire continent. This data is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment..

Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Balancing Authorities, Resource Planners and Tranmission Plannerss to obtain the data from a neighboring entity. Replacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes. The SDT concluded that because there is a reliability need for Planning Coordinators and Balancing Authorities to obtain demand data for their own reliability purposes and for data sharing between registered entities, a standard was appropriate.

NERC Glossary Term "Demand Side Management"

A couple of commenters asked the SDT not to change the NERC Glossary term "Demand Side Management." The intent in modifying the definition, however, was to respond to a FERC directive. The SDT has revised the definition to provide additional clarity.

Definition of Terms Used in Standard

Some commenters felt that it was not clear as to what Demand was being requested. In response to their concerns, the SDT developed a definition for Total Internal Demand. Upon acceptance of this standard, this definition will be moved to the NERC Glossary of Terms.

Purpose Statement

A commenter stated that the purpose statement and the title of the proposed standard only referenced Demand data but the requirements also requested energy data. The SDT modified the title as well as the purpose statement to address their concern. The SDT also modified the Purpose Statement to remove ambiguity and provide clarity that the intent of the standard is to define the responsibilities of both the requestor of the data and the respondent to the request as well as the data that could be requested.

Applicability Section

A few commenters questioned why the Balancing Authority would be subject to this standard. The SDT explained that they added the Balancing Authority due to the process used in the WECC. In most regions the Planning Coordinator is the collector of the data but in the WECC the Balancing Authority collects the data. Since this is meant to be a continent wide standard, the SDT needed to address the WECC process, and therefore included the Balancing Authority in the standard, as appropriate.

Administrative

A few commenters stated that they were not sure as to who was their Planning Coordinator. This is an issue that has been identified in other MOD projects and is currently being reviewed.

Requirement R1

One commenter expressed concern that the data being requested in the proposed standard could be burdensome and costly to collect. However, the SDT understood that this is not a new task or cost for entities. The majority of the data being requested is already required within the MOD-016 through MOD-019 and MOD-021 standards. Also, the data identified in Requirement R1 is included in either, or both, of the LTRA and Energy Information Administration’s Form EIA 411.

Another commenter did not believe that the FERC directive to provide for standardization of data collected was being addressed. The Requirement R1 standardizes the data that any entity, regardless of location, would be required to provide. The data listed in Requirement R1 Parts 1.3 through 1.5 is the minimum amount of data that would be required to support reliability studies or assessments.

The SDT modified the body of Requirement R1 to clearly state who the requestor could be and what data could be requested.

One commenter stated that they felt that Requirement R1 was open ended such that the data being requested may not be able to be collected within the time allowed. The SDT modified the requirement to limit the data that could be collected to only that which was outlined in the sub-parts. The SDT also modified the language to allow for “any or all” of the data to be requested. This was to allow for instances when a requestor may not have a reliability need to collect all of the data outlined within the standard.

The SDT modified the language in the sub-parts to provide additional clarity as to the type of data being requested.

A couple of commenters disagreed with the need to supply weather normalized actual data. The SDT is providing an equally effective and efficient method for responding to a FERC directive, which required the collection of temperature and humidity. The SDT believes that requiring hourly temperature and humidity values would provide no value since there are differing methods used to weather normalize Demand. The method an entity would use to weather normalize their actual data should be dependent on their unique system configuration.

The SDT removed the sub-requirement for an entity to identify entities within their footprint that were not part of their region. The SDT believes that this requirement did not provide any reliability benefit.

Requirement R2

The SDT modified Requirement R2 to clearly identify to whom the data owners should respond to for data requests developed under Requirement R1. The SDT removed the language from Requirment R2 allowing other neighboring entities to request data as it was felt that there was ambiguity in the language concerning who was requesting data and what data could be requested. The SDT added Requirement R4 to clearly identify the neighboring entities that could request data.

Requirement R3

The SDT modified the language in Requirement R3 to clearly state that the Planning Coordinator or Balancing Authority had an obligation to provide data collected to the Regional Entity when the Regional Entity requested the data. The SDT also added a minimum time frame for responding to a data request from the Regional Entity. This was to ensure that the Planning Coordinator or Balancing Authority would have sufficient time to gather the data and provide it to the Regional Entity.

Requirement R4

The SDT removed the language from Requirement R2 that dealt with allowing neighboring entities the right to request data and created Requirement R4 to allow for this situation. The SDT believes that by creating Requirement R4 it would remove the ambiguity that was created when it was combined with Requirement R2. Requirement R4 clearly states who can request data from a neighboring entity, the data that could be requested and the conditions for which a data owner could refuse to provide the data.

Violation Severity Levels (VSLs)

There were comments regarding concerns with the VSLs. All VSLs have been reviewed and modified as necessary to ensure proper alignment with the requirements.

RSAW

The SDT received comments requesting a Reliability Standards Audit Worksheet (RSAW). A pre- or draft RSAW is being provided in the form of a document titled “Compliance Input”. This document provides compliance assessment answers to questions and will be the basis for the contents of the RSAW.

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. The SAR and supporting package were posted for comment (July 2013).
2. First posting of the draft standard for a 45-day comment period and parallel ballot (July/August 2013).
3. Second posting of the draft standard for a 45-day comment period and parallel ballot (October/November 2013)

Description of Current Draft

This is the second posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
45-day Comment Period with Parallel Ballot	October/November 2013
Final ballot	December 2013
BOT adoption	December 2013

Effective Dates

MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to request that Demand be reduced. Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control, and Load as capacity resources.

Total Internal Demand: The Demand of a metered system which includes the Firm Demand, the DSM Load and the Load due to the energy losses incurred in the Transmission and distribution systems.

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: Demand and Energy Data**
2. **Number:** **MOD-031-1**
3. **Purpose:** To enumerate the responsibilities and obligations of requestors and respondents for the collection of Demand and energy data to support reliability studies and assessments.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "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 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that the purpose of this standard may be carried out various forms of historical and forecast demand and energy data and information must be available to the parties that perform the studies and assessments needed to ensure the adequacy of the Bulk Electric System (BES) and to be able to validate past events. The fundamental test for determining the adequacy of the BES is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 forecast (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhance the reliability of the BES. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure when Planning Coordinators (PC) or Balancing Authorities (BA) request data (R1), they identify the entities to provide the data (Applicable Entity in part 1.1), that the entities providing the data know what they are to provide (parts 1.3 – R 1.5) and the due dates (part 1.2) for the requested data.

R1. Each Planning Coordinator or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area.[1] The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

[1] For the Balancing Authority, "their area" encompasses their Balancing Authority Area as defined in the NERC Glossary of Terms. For the Planning Coordinator, "their area" encompasses the facilities for which the Planning Coordinator coordinates and integrates transmission facilities, service plans, resource plans, and protection systems.

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator in megawatts for the prior year.

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,[2] temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

Rationale for R2: This will ensure that entities identified in Requirement R1, that are responsible for providing data, provide the data in accordance with the details described in the data request developed in Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.4-1.6 of Requirement R1.

[2] For the purpose of this standard, the term "controllable load" means both Interruptible Load and Direct Control Load Management as referenced in FERC Order 693 Paragraph 1267.

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.*[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

Rationale for R3: This will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

Rationale for R4: This will ensure that Applicable Entity will provide the data requested by a Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;

- alter the format in which it maintains or uses the data; or
- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part

			Requirement R1, but did so after the date indicated in Requirement R1 part 1.2 but prior to 6 days after the date indicated in Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in Requirement R1 part 1.2 but prior to 11 days after the date indicated in Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in Requirement R1 part 1.2 but prior to 15 days after the date indicated in Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in Requirement R1 prior to 16 days after the date indicated in Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but did so after 75 days from the date of request but prior to 81	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but did so after 80 days from the date of request but prior to 86	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but did so after 85 days from the date of request but prior to 91	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to 91 days or more from the date of the request.

			days from the date of the request.	days from the date of the request.	days from the date of the request.	
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

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. The SAR and supporting package were posted for comment (July 2013).
2. First posting of the draft standard for a 45-day comment period and parallel ballot (July/August 2013).
3. Second posting of the draft standard for a 45-day comment period and parallel ballot (October/November 2013)

Description of Current Draft

This is the second posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
45-day Comment Period with Parallel Ballot	October/November 2013
Final ballot	December 2013
BOT adoption	December 2013

Effective Dates

MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after~~beyond~~ the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~In those jurisdictions where regulatory approval is not required, MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management (DSM): ~~The term for a~~All activities or programs undertaken by any applicable entity to request that D~~d~~emand be reduced. Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control, and L~~l~~oad as capacity resources~~influence the amount or timing of electricity they use~~.

Total Internal Demand: The Demand of a metered system which includes the Firm Demand, the DSM Load and the Load due to the energy losses incurred in the Transmission and distribution systems.

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: Demand and Energy Data**
2. **Number: MOD-031-1**
3. **Purpose:** To enumerate the responsibilities and obligations of requestors and respondents for the collection of Demand and energy data to support reliability studies and assessments.

~~3. ensure that actual and forecast Demand data necessary for assessment and validation of past events and to support future system assessment is reported.~~

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Planning Authority and~~/~~ Planning Coordinator (hereafter collectively referred to as the "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~~or~~ "Planning Coordinator."

4.1.2 Transmission Planner

4.1.3 Balancing Authority

4.1.4 Resource Planner

4.1.5 Load-Serving Entity

4.1.6 Distribution Provider

5. **Effective Date**

5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve 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:**

To ensure that the purpose of this standard may be carried out various forms of historical and forecast demand and energy data and information must be available to the parties that perform the studies and assessments needed to ensure the adequacy of the Bulk Electric System (BES) and to be able to validate past events. The fundamental test for determining the adequacy of the ~~Bulk Power System (~~BE~~P~~S~~)~~ is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 forecast (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand, Net Energy for Load and Demand Side Management data ~~projections~~ requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, ~~and~~ Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhance the reliability of the BE~~P~~S. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual D~~d~~emand and D~~d~~emand~~-~~ S~~s~~ide M~~m~~anagement performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure when Planning Coordinators (PC) or Balancing Authorities (BA) request data (R1), they identify the entities to provide the data (Applicable E~~responsible e~~ntity in part ~~R~~1.1), that the entities providing the data know what they are to provide (parts~~R~~ 1.3 – R 1.5~~7~~) and the due dates (part~~R~~ 1.2) for the requested data.

R1. Each Planning Coordinator or Balancing Authority may develop and issue a data ~~data reporting~~ request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area.[1] The data request shall include:~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity in a data request, shall develop and~~

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[1] For the Balancing Authority, "their area" encompasses their Balancing Authority Area as defined in the NERC Glossary of Terms. For the Planning Coordinator, "their area" encompasses the facilities for which the Planning Coordinator coordinates and integrates transmission facilities, service plans, resource plans, and protection systems.

~~issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include, at a minimum:~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data (“Applicable ~~Entity~~Entities”).

1.2. A ~~schedule detailing the~~ timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

~~**1.3.** The original data request from the Regional Entity.~~

~~1.4.~~1.3. A ~~requirement~~request to provide~~A request for~~ any or all of the following actual data, as necessary:

~~1.4.1.~~1.3.1. Integrated hourly Total Internal D~~d~~emands in megawatts ~~(MW)~~ for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal D~~d~~emands in megawatts~~MW and Net Energy for Load in gigawatthours (GWh)~~ for the prior year.

~~1.4.2.~~1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

~~1.4.3.~~1.3.4. ~~Monthly and a~~Annual peak hour weather normalized actual Total Internal D~~d~~emand~~s~~ in megawatts~~MW~~ for the prior year.

~~1.4.4.~~1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator in megawatts~~MW~~ for the prior year.

~~1.5.~~1.4. A ~~requirement~~request to provide any or all of ~~A request for t~~the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal D~~d~~emands in megawatts~~MW and Net Energy for Load in GWh~~ for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal D~~d~~emands (summer and winter) in megawatts~~MW and annual Net Energy for load in GWh~~ for ten calendar years into the future.

~~1.5.1.~~1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

~~1.5.2.~~1.4.5. Forecasts of Interruptible Load and Direct Control Load Management ~~(DCLM)~~ under the control or supervision of the System Operator for ~~at least five calendar years and~~ up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

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~~1.6.~~ A request~~A requirement for Applicable Entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported.~~

~~1.7.~~1.5. ~~A~~ to provide ~~an~~a summary explanation of the following, if necessary:~~requirement for Applicable Entities to provide:~~

~~1.7.1.~~1.5.1. The assumptions and methods used in the development of aggregated peak D~~d~~emand and Net Energy for Load forecasts.

~~1.7.2.~~1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

~~1.7.3.~~1.5.3. How Demand Side Management ~~measures are~~is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

~~1.7.4.~~1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,[2] ~~,~~ temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority ~~as identified by the Regional Entity in its data request,~~ shall have a dated data ~~reporting~~ request, either in hardcopy or electronic format, in accordance with Requirement R1.

Rationale for R2: This will ensure that entities identified in Requirement R1, that are responsible for providing data, provide the data in accordance with the details described in the data request~~reporting procedure~~ developed in Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.4-1.6 of Requirement R1.

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[2] For the purpose of this standard, the term "controllable load" means both I~~i~~nterruptible L~~l~~oad and D~~d~~irect C~~c~~ontrol L~~l~~oad M~~m~~anagement as referenced in FERC Order 693 Paragraph 1267.

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.~~Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the Planning Coordinator or Balancing Authority or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner) on request.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

Rationale for R3: This will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity.~~The entity identified by the Regional Entity in its data request, shall report the Applicable Entity's data as requested by the Regional Entity within the timeframe specified in the Regional Entity's request.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

Rationale for R4: This will ensure that Applicable Entity will provide the data requested by a Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or
- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

~~M1.~~M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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~~3~~, and Measures M1 through M4~~3~~, 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 or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address one of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4.~~N/A	N/A~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address two of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4.~~ ~~OR~~ ~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address one of the items listed in Requirement R1, Part 1.1 through Part 1.3, Part 1.4.1, Part~~	N/A ~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address three of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4.~~ ~~OR~~ ~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to address two of the items listed in Requirement R1,~~	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, did not develop a data reporting procedure.~~ ~~OR~~ ~~The Planning Coordinator or Balancing Authority, as identified by the Regional Entity, developed a data reporting procedure but failed to issue the data reporting request to the Applicable Entities identified in Requirement R1 Part 1.1.~~

				~~1.4.2 or Part 1.5.1 through Part 1.5.3.~~	~~Part 1.1 through Part 1.3, Part 1.4.1, 1.4.2 or Part 1.5.1 through Part 1.5.3.~~	~~OR~~ ~~The Planning Coordinator or Balancing Authority as identified by the Regional Entity, developed a data reporting procedure but failed to address any of the items listed in Requirement R1, Part 1.6 or Part 1.7.1 through Part 1.7.4.~~ ~~OR~~ ~~The Planning Coordinator or Balancing Authority as identified by the Regional Entity, developed a data reporting procedure but failed to address three or more of the items listed in Requirement R1, Part 1.1 through 1.3, Part 1.4.1, Part 1.4.2, or Part 1.5.1 through Part 1.5.3.~~
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of

			data requested in Requirement R1 part 1.5.1 through part 1.5.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so after the date indicated in Requirement R1 part 1.2 but prior to 6 days after the date indicated in Requirement R1 part 1.2. ~~N/A~~	requested items in Requirement R1 part 1.3.1 through part 1.3.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in Requirement R1 part 1.2 but prior to 11 days after the date indicated in Requirement R1 part	requested items in Requirement R1 part 1.3.1 through part 1.3.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in Requirement R1 part 1.2 but prior to 15 days after the date indicated in Requirement R1 part	the requested items in Requirement R1 part 1.3.1 through part 1.3.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in Requirement R1 prior to 16 days after the date indicated in Requirement R1 part 1.2. ~~The Applicable Entity, as defined in the data reporting request developed in Requirement R1, failed to provide the data requested to the~~

				1.2. ~~N/A~~	1.2. ~~N/A~~	~~requesting entity as defined in Requirement R1.~~
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but did so after 75 days from the date of request but prior to 81 days from the date of the request.~~N/A~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but did so after 80 days from the date of request but prior to 86 days from the date of the request.~~N/A~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but did so after 85 days from the date of request but prior to 91 days from the date of the request.~~N/A~~	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to 91 days or more from the date of the request.~~The entity as identified by the Regional Entity in its data request, failed to provide the data requested by the Regional Entity.~~
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Application Guidelines

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

> **Demand Side Management:** All activities or programs undertaken by any applicable entity to request that Demand be reduced. Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control and Load as capacity resources.

> **Total Internal Demand:** The Demand of a metered system which includes the Firm Demand, the DSM Load and the Load due to the energy losses incurred in the Transmission and distribution systems.

The defined term "Demand Side Management" is incorporated in the NERC approved standards listed in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand Side Management," it is not anticipated that the proposed revision will have any effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

MOD-031-1 shall become effective as follows:

The first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Demand-Side Management"

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term "Demand-Side Management"

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

> **Demand Side Management:** ~~The term for a~~All activities or programs undertaken by any applicable entity to request that Demand be reduced. Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control and Load as capacity resources. ~~influence the amount or timing of electricity they use.~~
>
> **Total Internal Demand:** The Demand of a metered system which includes the Firm Demand, the DSM Load and the Load due to the energy losses incurred in the Transmission and distribution systems.

The defined term~~proposed revised definition for~~ "Demand~~-~~ Side Management" is incorporated in the NERC approved standards listed~~, detailed~~ in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand~~-~~ Side Management,"~~,~~ it is not anticipated that the proposed revision will have any ~~adverse~~ effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

MOD-03~~0~~1-~~2~~1 shall become effective as follows:

The first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

1. ~~MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities.~~
2. ~~In those jurisdictions where regulatory approval is not required, MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.~~upon MOD-031-1 becoming effective.~~

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.~~upon MOD-031-1 becoming effective.~~

Attachment 1
Approved Standards Incorporating the Term "Demand-Side Management"

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MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term "Demand-Side Management"

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

Unofficial Comment Form

Project 2010-04 Demand Data (MOD C)
MOD-031-1 (Demand Data)

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. ET **Friday, November 22, 2013**.

If you have questions please contact Darrel Richardson or by telephone at 609-613-1848.

The project page may be accessed by clicking here.

Background Information

The Project 2010-04 Demand Data Standard Drafting Team posted an initial draft of the Standard MOD-031-1 (Demand Data) for comment from July 22, 2013 to September 4, 2013. The drafting team has revised the standard based on stakeholder comments and suggestions that the drafting team considered appropriate. The following is a summary of changes the drafting team has made:

- Modified the definition for Demand Side Management to provide additional clarity
- Added a definition for Net Internal Demand to provide clarity as to what data could be requested
- Modified the Purpose Statement to clearly state the intention of the standard
- Modified Requirement R1 to provide clarity as to:
  - who the data requestor was
  - that the data outlined in the sub-parts was the only data that an entity would need to provide
  - that all or a portion of the data outlined in the sub-parts could be requested
  - the data that could be requested
- Modified Requirement R2 to provide additional clarity as to the entity providing the data and to whom they need to provide the data
- Modified Requirement R3 to clrify that this requirement was only in effect when a Planning Coordinator or Balancing Authority received a request for data from the Regional Entity
- Added Requirement R4 to clarify:
  - the neighboring entities that could request data
  - the conditions for when a data provider could refuse to provide the data

- the data that could be requested
- Modified the VSLs to align with the modified requirements

This posting solicits comment on the revised MOD-031-1 standard. The standard responds to FERC Order 693 and lessons learned from compliance history.

Questions on MOD-031-1

1. **Please provide any issues you have on this draft of the MOD-031-1 standard and a proposed solution.**

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Demand Data		
Date Submitted:	July 18, 2013		
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC		
Telephone:	609-613-1848	E-mail:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.
Purpose or Goal (How does this request propose to address the problem described above?):
The pro forma standard consolidates the reliability components of the existing standards.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 693, remove ambiguity from the requirements, and incorporate lessons learned.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
An informal development ad hoc group is presenting a pro forma standard that consolidates the existing MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1 into a single standard. The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. The pro forma standard requirements are currently placed within a new standard, MOD-031-1.
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.)
Detailed description of this project can be found in the Technical White Paper of this SAR submittal package.

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.

Reliability Functions		
☒	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.
☒	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

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.
☐	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
MOD-001-1a	Available Transmission System Capability

Related Standards	
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None

Regional Variances	
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-031-1
July 3, 2013

Introduction
The NERC Compliance department (Compliance) worked with the 2010-04 Demand Data standard drafting team (SDT) to review the proposed standard MOD-031-1. The purpose of the review was to discuss the requirements of the pro forma standard 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-031-1 Questions

Question 1
In Requirement R2, will the auditor verify 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 sharing of data, the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard.

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

B. Requirements and Measures

R1. The Planning Coordinator or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Loads and Demande Side Management data from applicable entities in their area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts (MW) for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management in megawatts for the prior year.

1.4. A request to p[rovide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load[1], temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to

[1] For the purpose of this standard, the term "controllable load" shall refer to both interruptible load and direct control load management as referenced in FERC Order 693 Para 1267.

Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or
- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

White Paper on the MOD C Standards

MOD-016, MOD-017, MOD-018, MOD-019, and MOD-021

October 8, 2013

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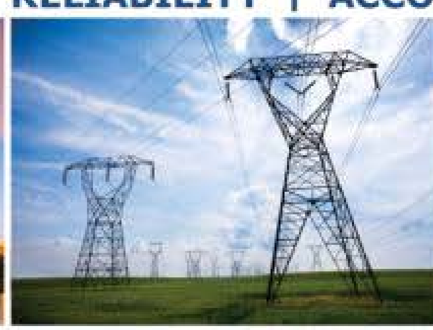


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Executive Summary

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the "MOD C" standards), were approved in the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 provides for the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 provides for the collection of interruptible demands and direct control load management.
- MOD-020-0 addresses the need to provide interruptible demands and direct control load management data to System Operators and Reliability Coordinators.
- MOD-021-1 provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC's Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC's Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

Although a pure data reporting standard would be a candidate for retirement under Paragraph 81, the data being collected has a reliability purpose in the development of future assessments for resource adequacy. It was decided to present a pro forma standard that consolidates the remaining five MOD C standards into a single standard, which was supported as the group conducted informal development outreach. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

As detailed below, the MOD C informal ad hoc group discussed the outstanding directives from FERC Order No. 693 and, through the informal development, provided a resolution to address each one.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of collecting data used in the analysis of resource needs. This document outlines the next generation of these standards and proposes to combine the reliability components of this package of standards into one standard. The remaining requirements in this package would either be retired as administrative or captured as instructional or explanatory in a white paper.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how NERC is addressing each of the outstanding FERC directives assigned to these FERC-approved standards. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. The contents of this paper are intended to assist the standard drafting team (SDT) assigned to MOD C and industry stakeholder participants with background information to move this standard package through the formal development process. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

Technical Discussion

The fundamental test for determining the adequacy of the bulk power system (BPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand projections requires coordination and collaboration between Planning Authorities/Planning Coordinators, Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts—as well as the supporting methods and assumptions used to develop these forecasts—will ultimately enhance the reliability of the BPS. Consistent documenting and information-sharing activities will also improve the efficiency of planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and Demand-Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

A second alternative to addressing data requirements in the absence of a standard is the implementation of either a Section 800 or Section 1600 data request. This approach, while effective, has a number of disadvantages. First, some Canadian provinces are not subject to FERC rule, which makes it more difficult for NERC to enforce an 800 or 1600 data request. The second issue is with entities within the continental United States. The 800 or 1600 data request is not mandatory and does not provide a mechanism to compel participation other than pursuing federal action under Section 215 of the Federal Power Act. In addition, using either of these approaches does not provide a mechanism for other LSEs, DPs, BAs or TPs to obtain the data from a neighboring entity.

The recommended option of modifying the existing standards to remove the ambiguity and address the FERC directives solves the issues identified with the first two options. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada. The informal development effort resulted in the recommendation for the development of a standard and has provided a draft version that combines the five existing standards into a single, comprehensive, and clear standard with three requirements.

Outstanding FERC Directives

There are 11 outstanding FERC directives from Order 693. Each of the directives was discussed in detail during the informal development stage, and summaries of the discussions can be found below. The ad hoc group extensively reviewed each of the directives with consideration of where the existing standards are today, where the group landed with the pro forma standard following its extensive industry outreach, and how the group addressed each directive.

The "Paragraph 81 initiative," which was issued by FERC in their March 15, 2012,[1] invited the ERO to identify possible requirements that have little to no effect on reliability that could be removed from the NERC Reliability Standards. The ad hoc group took the information from the FERC order into consideration when it discussed the directives related to the MOD C initiative.

Para 1232

Supported by many commenters, **the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans**. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. **Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.**

Consideration of Directive

With regard to the first directive, the ad hoc group is recommending that the Transmission Planner be added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Regarding the second directive, the ad hoc group is proposing a modified definition for Demand-Side Management (DSM). However, the group felt that the FERC proposed definition needed further clarity, so they modified it in an equally effective and efficient manner. It now reads:

> **Demand-Side Management:** The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

[1] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. Requirement R1 now requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3.4). The requirement now states that an entity must provide an explanation of how it used temperature and humidity to weather normalize its actual demands (Requirement R1 part 1.5.4).

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length and decided that there should not be an exemption. The group believes that if the load is not weather-sensitive then an explanation will be provided (Requirement R1 part 1.5.4), which will accomplish the same objective as providing an exemption.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. The requirement now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.5.4).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

The informal ad hoc group, as a result of its informal outreach, is recommending that the Transmission Planner be added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length with industry participants during informal outreach and decided that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length during its outreach and concluded that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

The SDT developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and

consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. The requirement now states that an entity must provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 part 1.5.3).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The approach is intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the Bulk Power System.

This white paper provides a record of how the ad hoc group and industry participants in the informal development decided to address the outstanding directives from FERC Order 693, along with the other components of the results-based standards, such as a risk-based and performance-based standard, along with incorporating the Paragraph 81 initiative.

Appendix A: Entity Participants

The below entities represent a nonexhaustive list of entities that had personnel that participated in the MOD-C 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, 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 C Informal Development				
Austin Energy	Hydro Quebec	MISO	PG&E	PSEG
American Transmission Co.	MEAG Power	NI Source	PJM	XCEL Energy
CenterPoint Energy	Flathead Coop	FERC	PSEG	MidAmerican
ERCOT				
Regional Entities				
FRCC				
MRO				
NPCC				
RFC				
SERC				
SPP				
TRE				
WECC				

Table 2: Presentations and Events	
NERC News	NERC Standards and Compliance Workshop
NERC Operating Committee	Reliability Assessment Subcommittee
NERC Planning Committee	Reliability Assessment Data Working Group
NERC Standards Committee	

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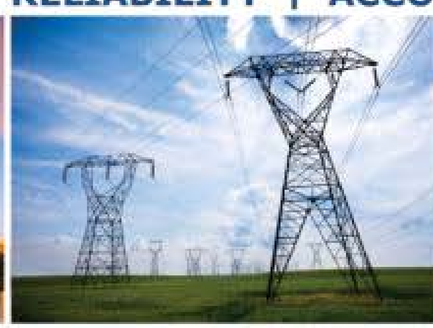


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The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

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Consideration of Directive

With regard to the first directive, the ad hoc group is recommending that the Transmission Planner be added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data ~~Reporting~~.

Regarding the second directive, the ad hoc group is proposing a modified definition for Demand-Side Management (DSM). However, the group felt that the FERC proposed definition needed further clarity, so they modified it in an equally effective and efficient manner. It now reads:

> **Demand-Side Management:** The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

[1] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data ~~Reporting~~. Requirement R1 now requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3~~4~~.4~~3~~). The requirement now states that an entity must provide an explanation of how it used temperature and humidity to weather normalize its actual demands (Requirement R1 part 1.5~~7~~.4).

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length and decided that there should not be an exemption. The group believes that if the load is not weather-sensitive then an explanation will be provided (Requirement R1 part 1.5~~7~~.4), which will accomplish the same objective as providing an exemption.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data ~~Reporting~~. The requirement now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.5~~7~~.4).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data ~~Reporting~~. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5~~7~~.4).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

The informal ad hoc group, as a result of its informal outreach, is recommending that the Transmission Planner be added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data~~ Reporting~~.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length with industry participants during informal outreach and decided that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

The informal ad hoc group discussed this issue at length during its outreach and concluded that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

The SDT developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data~~ Reporting~~. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5~~7~~.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data ~~Reporting~~. The requirement now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5~~7~~.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and

consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data ~~Reporting~~. The requirement now states that an entity must provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 part 1.5~~7~~.3).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The approach is intended to maintain NERC’s focus on developing and retaining requirements that support the reliable operation of the Bulk Power System.

This white paper provides a record of how the ad hoc group and industry participants in the informal development decided to address the outstanding directives from FERC Order 693, along with the other components of the results-based standards, such as a risk-based and performance-based standard, along with incorporating the Paragraph 81 initiative.

Appendix A: Entity Participants

The below entities represent a nonexhaustive list of entities that had personnel that participated in the MOD-C 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, 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 C Informal Development

Austin Energy	Hydro Quebec	MISO	PG&E	PSEG
American Transmission Co.	MEAG Power	NI Source	PJM	XCEL Energy
CenterPoint Energy	Flathead Coop	FERC	PSEG	MidAmerican
ERCOT				
Regional Entities				
FRCC				
MRO				
NPCC				
RFC				
SERC				
SPP				
TRE				
WECC				

Table 2: Presentations and Events

NERC News	NERC Standards and Compliance Workshop
NERC Operating Committee	Reliability Assessment Subcommittee
NERC Planning Committee	Reliability Assessment Data Working Group
NERC Standards Committee	

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Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R1	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirement R2	Requirement R2 of the standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5.
MOD-017-0.1 R1.1	Requirement R1 part 1.4.1	The standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.4.2	The standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.5.1	The standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.5.2	The standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	Requirement R1 part 1.6	This is no longer need now that all registered entities within each region is a member of that region.
MOD-018-0 R1.2	Requirement R1 part 1.7.1	The standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirement R2	The standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.5.3	The standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.7.2	The standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.7.3	The standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The standard will require entities to provide the requested data by a certain date.

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Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1~~ (the pro forma standard)~~

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data ~~reporting~~ request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The ~~pro forma~~ standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The ~~pro forma~~ standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R1	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirement R2	Requirement R2 of the ~~pro forma~~ standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5~~7~~.
MOD-017-0.1 R1.1	Requirement R1 part 1.4.1	The ~~pro forma~~ standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.4.2	The ~~pro forma~~ standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.5.1	The ~~pro forma~~ standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.5.2	The ~~pro forma~~ standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	Requirement R1 part 1.6	This is no longer need now that all registered entities within each region is a member of that region~~e pro forma standard will require entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported~~.
MOD-018-0 R1.2	Requirement R1 part 1.7.1	The ~~pro forma~~ standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirement R2	The ~~pro forma~~ standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5~~7~~.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.5.3	The ~~pro forma~~ standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.7.2	The ~~pro forma~~ standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.7.3	The ~~pro forma~~ standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The ~~pro forma~~ standard will require entities to provide the requested data by a certain date.

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DRAFT Reliability Standard Audit Worksheet[1]

MOD-031-1 – Demand and Energy Data

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						X[3]								
R2	X[4]	X[4]				X[4]								X[4]	
R3	X[5]						X[3,5]								
R4	X					X	X[3]			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.

[4] As identified by a Planning Coordinator or Balancing Authority in a data request issued per Requirement R1 Part 1.1 of MOD-031-1.

[5] As requested by applicable Regional Entity.

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 or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area.[6] The data request shall include:

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator in megawatts for the prior year.

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

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[6] For the Balancing Authority, "their area" encompasses their Balancing Authority Area as defined in the NERC Glossary of Terms. For the Planning Coordinator, "their area" encompasses the facilities for which the Planning Coordinator coordinates and integrates transmission facilities, service plans, resource plans, and protection systems.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,[7] temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with 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[8]:

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.
Copies of entity's data requests developed and issued in accordance with Requirement R1, or a statement that no data requests were issued.

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.

[7] For the purpose of this standard, the term "controllable load" means both Interruptible Load and Direct Control Load Management as referenced in FERC Order 693 Paragraph 1267.

[8] 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.

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.
	For data requests selected by auditor for audit testing, review and verify the request included items described in parts 1.1 and 1.2.

Note to Auditor: Items listed in parts 1.3 through 1.5.4 are optional and are included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard.

Entity assertions that no data requests were issued (see "a statement that no data requests were issued" in the Evidence Requested section above) do not have to be in writing.

Auditor Notes:

<u>R2 Supporting Evidence and Documentation</u>

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

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[9]:

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 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 responses to Planning Coordinator or Balancing Authority's data request(s) were made in accordance with Requirement R1 and within timetable established in part 1.2.

Note to Auditor: Based on the language in the requirement and the purpose of the standard, which is to facilitate the sharing of data to support reliability studies, the auditor should not only verify that the data was delivered within the timeframe(s) specified, but also verify that the data delivered met the requirements of the request. However, this standard does not specify criteria around quality of the data, so auditors should not make any assessments in that regard. The responding entity does not have to provide data beyond that requested per parts 1.3 through 1.5.4 of Requirement R1.

[9] 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.

Auditors at their discretion may communicate with Planning Coordinators or Balancing Authorities to determine if data requests made of entity under audit were delivered within the timeframe(s) specified and met the requirements of the request.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity.

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

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[10]:

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 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

[10] 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.

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, 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.
	Review evidence (documented date of the Regional Entity's request and entity's reply) to determine if they provided responses to Regional Entity's data request(s) in accordance with Requirement R3 and within 75 days from the receipt date of the data request.
Note to Auditor: Auditor should communicate with entity's Regional Entity to determine whether the Regional Entity had made a data request to the entity under audit. In the instance where the Planning Coordinator or the Balancing Authority collected additional data from Applicable Entities, the additional information may be provided to the Regional Entity but there is no obligation to do so under this requirement.	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to:

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or

- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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[11]:

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 listed in M4 as well as a copy of the data request; or a statement that a data request was not received.

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.

[11] 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.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, 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.
	Review evidence (documented date of request and reply) to determine if entity responses to data request(s) were made in accordance with Requirement R4 and within 45 days of the date of the written request.

Note to Auditor: Based on the language in the requirement and the purpose of the standard, which is to facilitate the sharing of data to support reliability studies, the auditor should not only verify that the data was delivered within the timeframe(s) specified, but also verify that the data delivered met the requirements of the request. However, this standard does not specify criteria around quality of the data, so auditors should not make any assessments in that regard. The responding entity does not have to provide data beyond that requested per parts 1.3 through 1.5.4 of Requirement R1.

Auditors, at their discretion, may communicate with the requesting Load Serving Entities, Planning Coordinators, Balancing Authorities, Transmission Planners, Resource Planners to determine if responses to data requests were appropriate in accordance with this Requirement.

Entity assertions that no data requests were issued (see "a statement that no data requests were issued" in the Evidence Requested section above) do not have to be in writing.

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/05/2013	NERC compliance, Standards	New Document

Standards Announcement Reminder

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Additional Ballot and Non-Binding Poll now open through November 22, 2013

Now Available

An additional ballot for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Friday, November 22, 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 standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps
The ballot results for **MOD-031-1** 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 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 (via email), 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

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Comment Period: October 9, 2013 - November 22, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: November 13, 2013 - November 22, 2013

Now Available

A 45-day formal comment period for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is open through **8 p.m. Eastern on Friday, November 22, 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 Friday, November 22, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll 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.

For more information or assistance, please contact Arielle Cunningham,
Standards Development Administrator, at Arielle.Cunningham@nerc.net or at 404-446-2560.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Comment Period: October 9, 2013 - November 22, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: November 13, 2013 - November 22, 2013

Now Available

A 45-day formal comment period for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is open through **8 p.m. Eastern on Friday, November 22, 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 Friday, November 22, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

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Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, November 22, 2013.**

This standard achieved a quorum but did not receive sufficient affirmative votes for approval. 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: 80.54% Approval: 57.59%	Quorum: 78.51% Supportive Opinions: 52.22%

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 standard shows the need for significant revisions, it will proceed to an additional comment period and ballot. If the standard does not show the need for significant revisions, it 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.

Ballot Results	
Ballot Name:	Project 2010-04 MOD-031-1 (MOD C)
Ballot Period:	11/13/2013 - 11/22/2013
Ballot Type:	Additional Ballot
Total # Votes:	298
Total Ballot Pool:	370
Quorum:	**80.54 % The Quorum has been reached**
Weighted Segment Vote:	57.59 %
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	101	1	46	0.613	29	0.387	0	9	17
2 - Segment 2	9	0.7	3	0.3	4	0.4	0	0	2
3 - Segment 3	81	1	33	0.55	27	0.45	0	6	15
4 - Segment 4	29	1	11	0.5	11	0.5	0	1	6
5 - Segment 5	86	1	33	0.6	22	0.4	0	10	21
6 - Segment 6	49	1	21	0.568	16	0.432	0	3	9
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	2	0.2	1	0.1	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.8	5	0.5	3	0.3	0	0	0
Totals	**370**	**7**	**156**	**4.031**	**113**	**2.969**	**0**	**29**	**72**

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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Company)
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	Affirmative	
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		
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	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion comments submitted under a seperate ballot)
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 - (PJM 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	Negative	COMMENT RECEIVED

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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
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	Abstain	
1	Lincoln Electric System	Doug Bantam		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
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	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 - (NPPD)
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	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC)
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC Position Paper)
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		
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	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comments)
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 - (Public Service Company of New Mexico (PNM))
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		
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	Negative	COMMENT RECEIVED
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	Abstain	
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	Negative	COMMENT RECEIVED
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
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		
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (serc)
2	Southwest Power Pool, Inc.	Charles H. Yeung		
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	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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		
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Palo Alto	Eric R Scott	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Company)
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	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - PJM
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corportation)
				SUPPORTS

3	Great River Energy	Brian Glover	Negative	THIRD PARTY COMMENTS - (MRO's 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	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)
3	Los Angeles Department of Water & Power	Mike Anctil	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC)
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 - (NPPD comments submitted by Don Schmit)
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
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 - (Southwest Power Pool)
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		
3	Platte River Power Authority	Terry L Baker	Abstain	
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	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	Affirmative	
3	Santee Cooper	James M Poston	Abstain	

3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comments)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Company of New Mexico (PNM))
3	South Carolina Electric & Gas Co.	Hubert C Young		
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		
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	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Company)
4	Consumers Energy Company	Tracy Goble		
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 Corporation GTC)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO, Florida Municipal Power Agency, SERC PSS, and PJM)
				SUPPORTS THIRD PARTY COMMENTS -

4	Indiana Municipal Power Agency	Jack Alvey	Negative	(Florida Municipal Power Agency - Frank Gaffney)
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 - (PJM)
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Company of New Mexico (PNM))
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comments)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Brett 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	Affirmative	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
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	Abstain	
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		
5	Cleco Power	Stephanie Huffman		
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	Abstain	
				SUPPORTS

5	Dominion Resources, Inc.	Mike Garton	Negative	THIRD PARTY COMMENTS - (Dominion)
5	DTE Energy	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Company)
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Association)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
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	COMMENT RECEIVED
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	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Bonnie Marino-Blair		

5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon		
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	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 - (Bret Galbraith on behalf of Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Company of New Mexico (PNM))
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		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
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		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
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 Martin	Affirmative	
6	City of Redding	Marvin Briggs	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	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Company)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (PJM)
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		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (In support of Nebraska Public Power District (NPPD))
6	Los Angeles Department of Water & Power	Brad Packer		
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	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC Comment)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service

				Company of New Mexico (PNM))
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		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
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	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	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS comments submitted on 11/22/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	COMMENT RECEIVED

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Non-Binding Poll Results

Project 2010-04 (MOD C)
MOD-031-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-04 MOD-031-1 (MOD-C)
Poll Period:	11/13/2013 - 11/22/2013
Total # Opinions:	263
Total Ballot Pool:	335
Summary Results:	78.51% of those who registered to participate provided an opinion or an abstention; 52.22% 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		
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		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
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	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		
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	Abstain	
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 - (PJM 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	Negative	COMMENT RECEIVED
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Abstain	
1	Lincoln Electric System	Doug Bantam		
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	Affirmative	
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	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 - (SPP)
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	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC)
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)

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	Negative	SUPPORTS THIRD PARTY COMMENTS - (WECC Position Paper)
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	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	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson	Abstain	
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 - (Public Service Company of New Mexico (PNM))
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		
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	Abstain	
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	Abstain	
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	Negative	COMMENT RECEIVED
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (serc)
2	Southwest Power Pool, Inc.	Charles H. Yeung		
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	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Palo Alto	Eric R Scott	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	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	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - PJM
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's 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 Municiapl Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power

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				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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments)
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
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 - (Southwest Power Pool)
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		
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	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
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)

NERC

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 - (Public Service Company of New Mexico (PNM))
3	South Carolina Electric & Gas Co.	Hubert C Young		
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		
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	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
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		
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 Corporation GTC)
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 - (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 - (PJM)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Company of New Mexico (PNM))
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Brett 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	Affirmative	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
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		
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	Abstain	
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	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	Abstain	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak	Affirmative	- (MISO)
5	Duke Energy	Dale Q Goodwine	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	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
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		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	

5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
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 - (SPP)
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	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon		
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	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 - (Bret Galbraith on behalf of Seminole Electric Cooperative Inc)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Public Service Company of New Mexico (PNM))
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		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
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 Martin	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	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
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		
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	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	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be subitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service

				Company of New Mexico (PNM))
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
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	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	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PSS comments submitted on 11/22/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	COMMENT RECEIVED

Individual or group. (43 Responses)
Name (26 Responses)
Organization (26 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (43 Responses)
Question 1 (27 Responses)
Question 1 Comments (37 Responses)

Group
MRO NERC Standards Review Forum
Russel Mountjoy
The NSRF is generally satisfied with the first draft of the proposed MOD-031 standard as posted by the SDT. Several changes made by the drafting team since the initial draft, although well intentioned, are cause for concern the industry. 1. The drafting team has added a proposed new requirement R4, which would require small entities to respond to requests for demand and energy data from a host of other potential entities by either providing the requested data or providing an explanation for why the data was not provided. We find this proposed requirement particularly troubling, in that it potentially puts us in the position of determining whether an entity requesting demand and energy data has a demonstrated reliability need for such data and then justifying that determination to an auditor under fear of violating a mandatory reliability standard. We believe it is reasonable to require entities to provide the requested demand and energy data to our immediate PC or BA once per year under the reliability standard. We do not believe it is reasonable to require every entity to add a compliance process to respond to every potential request for this information under the standard. Recommend that “once per year (annually)” be added to R1 and R2 to align with our comments above 2. The proposed updated definition of DSM allows entities to determine the “activities or programs” that will fall under their DSM program. Yet in R1.3.5 and R1.4.5, the SDT quantifies the request for only “Interruptible Load and Direct Control Load Management”. If an entity has determined other “activities or programs” that are within their DSM program, should that be reported too? There may be entities that these other types of “programs and activities” that should be used to support reliability studies and assessments as stated in the Purpose of this Standard. Please clarify. 3. The SDT has proposed the definition of Total Internal Demand (TID). TID The drafting team has proposed a new definition “Total Internal Demand”, and further proposes to use that definition throughout the standard in specifying information that must be supplied (R1.3.1, R1.3.2, R1.3.4, R1.4.1, and R1.4.3). The rationale for making this change is not clear, but appears to be an attempt to tie the requirements of the standard back to the current LTRA/EIA-411 data request form?. Contrary to the stated goal of the drafting team, the proposed changes seem to make the data requirements less clear, if not impossible to provide. For example, as proposed, R1.3.1 would request hourly Total Internal Demands in megawatts for the prior year. Based on the proposed definition of Total Internal Demand, it

could be implied that entities would be required to be able to measure the impact of DSM programs (DSM Load) on an hourly basis. The NSRF does not believe that load serving entities can accurately and reasonably determine these DSM impacts over all hours in a year. R1.3.4, as currently proposed, would appear to require entities to report annual peak hour weather normalized actual Total Internal Demand. It is not clear to NPPD what this term means, particularly as it relates to the normalization of DSM impacts. Please clarify. In addition, the proposed definition appears to create a disconnect between various requirements in the standard. For example, as proposed, R1.3.2 would require monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year to be reported. Based on the definition of Total Internal Demand, Applicable Entities should provide data that includes the impact of DSM programs, based on the expanded definition of DSM. However, in R1.3.5, the DSM data to be reported is limited to IL and DCLM under the control or supervision of the System Operator. Thus there is the potential for DSM program impacts to be reflected in the Total Internal Demand values (R1.3.2) that are not accounted for in R1.3.5. There would appear to be a similar disconnect regarding forecast peak demand and DSM data (R1.4.1 & R1.4.3 vs. R1.4.5). Please see comments above concerning this issue (#2). The NSRF proposed solution would be to drop the definition and use of “Total Internal Demand” throughout the standard and return to the original use of just “Demand” (e.g., “peak hour actual Demand”, peak hour forecast Demand”, etc.) 4. The drafting team has proposed some significant changes to the language of Requirement R1, such that it would now include the statement “Each Planning Coordinator or Balancing Authority may develop and issue a data request…” (emphasis added). Measuremet 1 (M1) requires the PC / BA to have dated evidence of a data request (emphasis added). The measure needs to directly state what is within the Requirement. If “may” is used with R1, then M1 should read “…shall have, when applicable…”. We are to understand that there may be regions that collect some of this data by another means (not by data request). In those areas then, their data request should state that entities can provide data by the other means that they use. To use words like “may” and “if necessary” in a Standard causes confusion and makes one wonder if any of it is really required.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
In the response to comments, "Several commenters stated that the exising MOD C standards (MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, MOD-020-0 and MOD-021-1) should be retired. Commenters argued that the data could be collected by NERC and the Regional Entities through data requests issued pursuant to Section 800 or Section 1600 of NERC’s Rules of Procedure. First, the standard provides an efficient and enforceable mechanism for NERC and the Regional Entities to obtain demand data from all relevant registered entities across the entire continent. This data is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment." this decision has not been adequately justified if the industry truly has the ability to draft standards when their is really a reliablity need. In this instance there is no gap in realibility that has been demonstrated. Data is flowing as needed

and Balancing Authorities and Planning Coordinators have sufficient authority to request any relevant data they are currently not receiving.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Regarding the definition of Demand Side Management(DSM): It is not clear whether the proposed DSM definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management has a temporary impact. Suggest revising the DSM definition as follows: Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to reduce Demand. Examples of DSM may include, but are not limited to, Passive Demand Reduction (PDR) and Dispatchable Demand Reduction (DDR) measures, Direct Control Load Management (DCLM), Interruptible Load, critical peak pricing (CPP) with control, and Load as capacity resources. Demand-related technologies are evolving rapidly and are quickly propagating throughout the industry. The standard should be designed to accommodate change and increasing DSM market penetration as well. Suggest defining two broad categories of demand-related technologies which are (1) load reductions, and (2) capacity-related, as follows: Passive Demand Reduction (PDR) – Non-dispatchable related technologies reduce peak load and energy consumption. It is anticipated that the Total Internal Demands and Net Energy for Load will reflect these PDR reductions. Typically they are not netted out of the normalized Total Internal Demand. PDR’s are not under the control or supervision of the System Operator. Dispatchable Demand Reduction (DDR) – Dispatchable related technologies to reduce peak load and energy consumption. Generally, these DDR resources can be counted as equivalent to installed capacity, and may receive installed capacity credits similar to those provided traditional installed generating resources. DDR’s are under the control or supervision of the System Operator. Regarding the definition of Total Internal Demand: It is not clear what the intent of the meaning of the term "Firm" in the definition of Total Internal Demand is. Load forecasts are total load, regardless of whether it is firm (assuming not counting interruptible load). Interruptible load is not forecasted. More clarity is required for this definition. Requirements: Regarding Requirement R1, Part 1.1, and sub-parts 1.3.5, 1.4.5 and 1.5.4, depending on market design, the Planning Coordinators and/or Balancing Authority may be in the best position to determine this data. Transmission Planners, Load Serving Entities and Distribution Providers may not be able to provide or determine this data. Part 1.5 may lead to the use of inconsistent reporting and forecasting methodologies and/or double-counting of demand-related resources. The Planning Coordinator or Balancing Authority should specify an expected reporting and forecasting basis for Total Internal Demand, Net Energy for Load and Demand Side Management data from Applicable Entities in their area, including the reporting of Passive Demand Reduction and Dispatchable Demand Reduction adjustments. Each Applicable Entity should verify that no double-counting exist in its reporting. Recommend that a requirement be added to require that each Applicable Entity verify that no double-counting exist in its reporting. Each Planning Coordinator, Planning Authority, Transmission Planner,

Balancing Authority, Resource Planner, Load-Serving Entity, and Distribution Provider shall verify that no double-counting of demand-related resources exist in its reporting. Also recommend that a new requirement be added to establish that the PC or BA have responsibility for verifying that there is no double-counting across LSE's and DP's reporting. Each Planning Coordinator, Planning Authority or Balancing Authority shall verify that no double-counting of demand-related resources exists in the reported data.
Individual
Thomas Breene
Wisconsin Public Service Corporation
Yes
WPSC has the following comment on Requirement 1.5.4. 1) R1 1.5.4. "How the peak load forecast compares to actual load for the prior year with due regard to controllable load, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted." A) "With due regard" is vague. It doesn't clearly explain what is asked for. Suggest removing this language for something more clear. B) Language doesn't clearly indicate that only the annual peak is requested to be weather normalized and adjusted for interruptible load taken. This could be misinterpreted. • Suggested Changing the Language to: "How the annual peak load forecast compares to the annual peak actual load for the prior year after weather normalization (required in 1.3.4) and if applicable, adjusting for controllable load that may have been interrupted (realized). Based on comparison please explain if assumptions or methods for future forecasts were adjusted."
Group
Salt River Project
Bob Steiger
Yes
The footnote at the bottom of page 5 of the Clean Draft Standard separates "transmission facilities" from "service plans" to generate four requirements for defining the area for Planning Coordinators. Because of this syntax, "service plans" could be interpreted as something unrelated to transmission facilities. "Planning Authority" in the NERC Glossary of Terms states that "transmission facility and service plans" are one of the three required planning sections. This footnote would potentially support an interpretation that is not consistent with the NERC Glossary of terms. The footnote should be consistent with the NERC Glossary of Terms by replacing "transmission facilities, service plans, resource plans and protection systems" with "transmission facility and service plans, resource plans, and protection systems". The new definition for "Total Internal Demand" includes DSM Load. The definition should specify whether this is the inclusion of a positive or negative number. One interpretation is that inclusion means that the impact of DSM has been considered in system demand, while another is that DSM is included by not reducing demand for DSM. The definition should clarify whether inclusion means that load is gross demand or demand net of DSM. (Is DSM a resource or a demand reduction?)
Individual

Kathleen Goodman
ISO New England, Inc.
Agree
IRC SRC
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC Planning Standards Subcommittee
Individual
Laurie Williams
Public Service Company of New Mexico
Yes
The current draft of MOD-031 attempts to define what a “PC area” is. PNM strongly disagrees with the use of this Standard to define a PA/PC "area". This is obviously an on-going issue that needs to be resolved ultimately in the NERC Rules of Procedure and a Standard is not the appropriate place to try to create this functional definition. As such, we believe that the footnote associated with R1 should be removed or NERC risks creating an inconsistency between the Standards and any clarification that might subsequently be made to the Rules of Procedure. Additionally, PNM disagrees with the language in R1. Specifically, the word "may" should be replaced with "shall" in R1. The word "may" is unclear and would create difficulties in determining compliance in audits and other monitoring processes. Both the 'Rationale for R1' and the 'Purpose' in the Standard attempt to "enumerate the responsibilities and obligations" of the parties subject to the standard, but the language in R1 in this draft version does not clearly do that with the word "may".
Individual
Thomas Foltz
American Electric Power
Yes
AEP questions the need for this standard, and does not believe it provides any reliability benefit to the BES. Much has changed in the way this information is gathered and reported, and having such a prescriptive standard is not beneficial. To that point, the RTO’s already have established processes which fulfills the need. As a result, AEP does not support pursuing MOD-031-1. In addition, this standard dictates how and what type of information is needed for the PC and the BA to do their assessments. It might be preferable that the standard focus on the *what* rather than the *how* and establish a framework for supporting entities to meet the PC and BA’s expectations. We much prefer the approach taken in IRO-010-1a where the standard does not prescribe the details of the data request. Another example is the proposed standard MOD-032 which addresses similar requirements at a higher level, which we believe is far more appropriate and preferable to the highly prescriptive direction taken in MOD-031-1.

The comments below are provided in the event the project team continues to pursue the proposed MOD-031-1 standard. R 1.1 – It should be made clear that the list of Functional Entities is provided solely as examples, and is not a requirement that all must be included in the data request. There may be circumstances where RE and Planning Coordinator boundaries do not properly align with the manner in which the requirements are written. The VSL associated with not meeting the expectations of such a data request is Severe. We disagree with the open-endedness of R1, as well as its sole VSL of Severe. AEP recommends changing the proposed definitions to the following: Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to influence the amount or timing of electric usage. Total Internal Demand: The Demand of a metered system which includes the Net Internal Demand, the Demand Response Load and the Load due to the energy losses incurred in the transmission and distribution systems. In addition, we believe the following (new) definitions need to be added to the Definition of Terms section: Demand Response (DR): All programs undertaken by any applicable entity to request that demand be reduced. Examples of DR may include, but are not limited to, Load Management Programs, Direct Control Load Management (DCLM), Interruptible Load or Interruptible Demand, Critical Peak Pricing (CPP) with control, and Load as Capacity resources. Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, less Demand Response (i.e., Direct Control Management and Interruptible Demand). Demand Forecast on Normal Weather Basis: A forecast that has been adjusted to reflect normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 forecast (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). Additional suggestions (all pages reference the “clean” version of draft document): Pg 5 R1: remove “as necessary” Pg 6, R1.3.5 & 1.4.5 change “Interruptible Load and Direct Control Load Management” to “Demand Response” Pg 6, R1.5.1 change “aggregate peak’ to “Total Internal”
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
a) Background – In the last paragraph, first line, ‘demand’ should be capitalized. Also, Balancing Authority is not listed in this paragraph but they are listed as a Functional Entity in the standard. b) R1, R2, R3 – there is no stipulation that the request needs to be in writing although the Measures for these requirements seem to imply that the request would be in writing given the suggested evidence. R4 specifically refers to written request which is inconsistent with the other data requests contemplated by the standard. c) R1, 1.3 and 1.4 and 1.5 – all of these parts indicate that the data will be requested ‘as necessary’ but there is no further information given as to determining necessity so one would assume it is in the requestor’s discretion as to what is necessary. In R4, however, each requestor needs to have ‘a demonstrated reliability need’ for the data that is being requested. Is the same concept of ‘need’ meant to apply to the word necessary in 1.3, 1.4 and 1.5? d) R1, 1.3 – unclear whether the references to ‘prior year’ are meant to be to ‘prior calendar year’ or the prior 12 month

period. e) R1, 1.5.4 – footnote 2 – would suggest adding this as a new defined term, which seems more in line with practice in standards drafting as opposed to including a new definition in a footnote. f) R4, M4 – Distribution Provider is not listed in the list of entities that may make a request – is this a purposeful or inadvertent omission? g) R4, 4.1 – there is no detail given with respect to determining whether a requesting entity demonstrated a reliability need so the assumption is that this is left to the Applicable Entity's sole judgment and discretion. h) VSLs, R1 – the words 'entity(s) necessary to provide the data' could be replaced with 'Applicable Entity(s)'. i) VSLs, R2 – the final paragraph under Severe VSL should read ' more than 15 days' as opposed to 'prior to 16 days'. j) VSLs, R3 – Severe VSL – instead of 'prior to 91 days or more from', it should read 'more than 91 days after'.
Individual
Andrew Z.Pusztai
American Transmission Company, LLC
Yes
ATC recommends the following changes be made to the draft Standard: 1. ATC recommends changing the specified time period in sub-requirement 1.3.1 through 1.3.5 from 'the prior year' to 'a prior 12 month period'. This change provides the same function as the original text with added flexibility. 2. ATC recommends to modify Requirement R1.4.3 by adding the word "Annual" at the start of the sub-requirement. a. R1.4.3 would read: "Annual peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future." b. This change aligns MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest. 3. ATC recommends to modify Requirement R1.4.5 by adding the word "Annual" at the start of the sub-requirement. a. R1.4.5 would read: "Annual forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions." b. This change aligns MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest. 4. ATC believes additional dispersed (interconnection point by interconnection point) actual load data is required for reliability studies and assessments. This concern was addressed in MOD-016 and has not been included in either MOD-031 or MOD-032. If the dispersed actual load data were added to MOD-031, the following changes are recommended a. Add an item 'Dispersed Actual Load data' to the list of required collected items in the text of R1: "Total Internal Demand, Net Energy for Load, Demand Side Management, and Dispersed Actual Load data". b. Add a Requirement R1.3.6 that states "Dispersed (interconnection point by interconnection point) actual Demand data in megawatts and megavars (summer peak, winter peak, representative minimum load and shoulder load periods) in the prior 12 month period". 5. ATC believes additional dispersed (interconnection point by interconnection point) forecast Demand load 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. If the dispersed forecast Demand load data were added to MOD-031 the following changes are recommended. a. Add a Requirement R1.4.6 that states "Dispersed (interconnection point by interconnection point)

forecast Demand load data in megawatts and megavars for ten calendar years into the future.” b. This new requirement should also require Applicable Entity to provide basic load characteristics information such as scalable or non-scalable, percentages of dynamic load, monthly peak load variations etc. 6. ATC believes there are no requirements accounting for non-member contribution to load. This concern was addressed in MOD-018 and has not been included in MOD-031-1 (non-members could be explicitly included in MOD-031-1 R1.6). Consider adding Requirement 1.6 wording as follows, “A request to provide estimated actual and forecast demand and net energy for load data of entities that are not registered with a Regional Entity and are not a member of a Balancing Authority.” 7. ATC believes M4 should specify the request and request date be documented. This change allows clear documentation of meeting the specified 45 day timeline.
Individual
Becky Stewart
Idaho Power
Yes
In Idaho Power's case, WECC, the Regional Entity, has previously acted as the Planning Coordinator as far as the activities outlines in this standard are concerned. However, WECC is not officially the Planning Coordinator. It is, therefore, difficult to assertain how the requirements outlined here would apply to us vs. how they would apply to WECC, especially as relates to the 75- and 45-day timeline requirements.
Individual
Don Schmit
Nebraska Public Power District
Yes
Nebraska Public Power District (NPPD) was generally satisfied with the first draft of the proposed MOD-031 standard as posted on the NERC website in July 2013. Several changes made by the drafting team since the initial draft, although well intentioned, are cause for concern by NPPD. 1. The drafting team has added a proposed new requirement R4, which would require entities such as NPPD to respond to requests for demand and energy data from a host of other potential entities by either providing the requested data or providing an explanation for why the data was not provided. NPPD finds this proposed requirement particularly troubling, in that it potentially puts us in the position of determining whether an entity requesting demand and energy data has a demonstrated reliability need for such data and then justifying that determination to an auditor under fear of violating a mandatory reliability standard. We believe it is reasonable to require entities like NPPD to provide the requested demand and energy data to our immediate PC or BA once per year under the reliability standard. We do not believe it is reasonable to require NPPD to to add a compliance process to respond to every potential request for this information under the standard. NPPD’s believes that R4 should be eliminated and any requests from other entities for this data should be directed to the applicable PC or BA and they should be the clearinghouse for such requests. NPPD further believes that the response to such requests should be coordinated through the

PC or BA as business practice and this should not be a Standard requirement. As noted earlier NPPD also believes that in Requirement R1 the PC or BA shall issue a maximum of one request annually for demand and energy data. R2 would likewise be modified to indicate that an Applicable Entity, such as NPPD, would be required to respond to a maximum of one request annually from its immediate PC or BA. 2. The drafting team has proposed an expanded definition for Demand Side Management (DSM), that as NPPD understands would replace the current definition in the Reliability Standards Glossary of Terms and become applicable not only to MOD-031, but to all other standards referring to DSM. The proposed definition is very broad in nature and therefore fails to meet the drafting team's objective of providing additional clarity. Later in the standard, specific requirements such as R1.3.5 and R1.4.5 specify the DSM information to be provided as Interruptible Load (IL) and Direct Control Load Management (DCLM) under the control or supervision of the System Operator. This is a significantly more limited subset of potential DSM programs than indicated by the proposed definition. NPPD's preferred solution would be for the definition of DSM to be more closely aligned with the specific information being requested in R1.3.5 and R1.4.5. If that is not possible, our next preferred solution would be to completely eliminate the DSM definition from the standard. 3. The drafting team has proposed a new definition "Total Internal Demand", and further proposes to use that definition throughout the standard in specifying information that must be supplied (R1.3.1, R1.3.2, R1.3.4, R1.4.1, and R1.4.3). The rationale for making this change is not entirely clear to NPPD, but appears to be an attempt to tie the requirements of the standard back to the current LTRA/EIA-411 data request form. Contrary to the stated goal of the drafting team, the proposed changes seem to NPPD to make the data requirements less clear, if not impossible to provide. For example, as proposed, R1.3.1 would request hourly Total Internal Demands in megawatts for the prior year. Based on the proposed definition of Total Internal Demand, it could be implied that entities would be required to be able to measure the impact of DSM programs (DSM Load) on an hourly basis. NPPD does not believe that load serving entities can accurately and reasonably determine these DSM impacts over all hours in a year. R1.3.4, as currently proposed, would appear to require entities to report annual peak hour weather normalized actual Total Internal Demand. It is not clear to NPPD what this term means, particularly as it relates to the normalization of DSM impacts. In addition, the proposed definition appears to create a disconnect between various requirements in the standard. For example, as proposed, R1.3.2 would require monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year to be reported. Based on the definition of Total Internal Demand, Applicable Entities should provide data that includes the impact of DSM programs, based on the expanded definition of DSM. However, in R1.3.5, the DSM data to be reported is limited to IL and DCLM under the control or supervision of the System Operator. Thus there is the potential for DSM program impacts to be reflected in the Total Internal Demand values (R1.3.2) that are not accounted for in R1.3.5. There would appear to be a similar disconnect regarding forecast peak demand and DSM data (R1.4.1 & R1.4.3 vs. R1.4.5). NPPD's proposed solution would be to drop the definition and use of "Total Internal Demand" throughout the standard and return to the original use of just "Demand" (e.g., "peak hour actual Demand", peak hour forecast Demand", etc.) 4. The drafting team has proposed some significant changes to the language of Requirement R1, such that it

would now include the statement “Each Planning Coordinator or Balancing Authority may develop and issue a data request…” (emphasis added). Measuremet 1 (M1) requires the PC / BA to have dated evidence of a data request (emphasis added). The term “may” in R1 should be changed to “shall”. In addition, in R1.3, R1.4 and R1.5 eliminate the words “as (if) necessary”. We are to understand that there may be regions that collect some of this data by another means (not by data request). In those areas then, their data request should state that entities can provide data by the other means that they use. To use words like “may” and “if necessary” in a Standard causes confusion and makes one wonder if any of it is really required.
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
Thank you Standard Drafting Team Members for all of your work! We do not see that this standard has any significant impact on the Bulk Electric System, especially in the short term. Please re-consider the VRFs and VSLs. We believe that they are way to severe given the lack of risk to the Bulk Electric System.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
City of Austin dba Austin Energy (AE) requests the SDT to review the VSL for R2. It appears there is a 1-day gap between the high and severe VSL. An entity submitting the data 15 days after the deadline does not fall under any VSL as written.
Group
WECC
Steve Rueckert
WECC staff supports the fundamentals of the requirements and the concept of the single standard, but has concerns with the current language and timing requirements included in several of the requirements. Requirement R1 currently indicates the PC or BA “may develop and issue a data request, as necessary…” WECC staff believes this language should be changed to “shall develop and issue a data request.” The words “may develop” and “as requested” seem inappropriate and vague for mandatory requirement language. M1 also requires a copy of the data request to show compliance. If the entity MAY develop the request, but elects not to, how can M1 be demonstrated? The numbering in the Rationale for R2 is off. The scope of parts 1.4-1.6 should be 1.3-1.5. WECC staff supports and thanks the drafting team for the inclusion of the PC or the BA as the applicable entity. AS noted in the response to comments, in most regions the PC is the collector of the data, but in WECC the BA has historically collected the data. By identify the PC or the BA, the WECC practice may continue. The WECC staff also noted a minor concern with the language of several parts of Requirement R1. Monthly and annual peak data are required in several parts. WECC staff questions whether or not providing monthly peaks also provides the annual peak. If so, why ask for both. If it is the intent that two

numbers be provided in parts 1.3.5 and 1.4.5, WECC staff suggests revision of the wording to make it clear that both the amount of Interruptible plus Direct Control Load Management deployed (i.e., called or activated) and the amount realized are being requested as separate values. Additionally, WECC staff suggests that the amount of DSM served (i.e., not called or activated) be requested. The words “as necessary” and “any of all of” appear in several parts of Requirement R1. WECC staff believes these phrases should be deleted. If an applicable reporting entity does not have a certain type of Demand to report, the reporting entity can report zero. In parts 1.3.5 and 1.4.5 of Requirement 1 WECC staff questions whether it is intentional that the collection of forecast (and actual) data for the critical peak pricing and Load as Capacity Resources DSM categories are being excluded from this part. As monthly peak and energy data is needed to perform probabilistic studies, WECC staff recommends that parts 1.4.1 and 1.4.2 be changed to say “at least the next two calendar years, and up to eleven calendar years”. With these changes parts 1.4.3 and 1.4.4 could be eliminated as they are duplicative of the data requested in parts 1.4.1 and 1.4.2. WECC staff also believes that forecast data should be requested for eleven calendar years rather than ten. Currently, the NERC ten year study does not include the next year, resulting in the last year of the study actually being the eleventh year. For example, the years 2014-2023 are reported in the 2013 LTRA. If the 2013 request only asks for ten years of data, 2023 will be left out (2013-2022). WECC staff believes that Requirement R3 should be revised to change the 75 day period for the PC or the BA to provide the data collected to the applicable Regional Entity to 45 days. Current schedules for data collection from NERC will not allow for 75 days. The 75 day period could be retained if NERC changes their schedule for data collection and requests the data sooner. WECC staff also has several concerns with the proposed Defined Terms for the standard. The words "All activities" and "request" in the definition of Demand Side Management (DSM) seemingly encompass public appeals, which are not generally identified as DSM and cannot logically be included as a component of Total Internal Demand. Hence, either a) the DSM definition should be revised so that it includes only programs that require a pre-consent to experience a service interruption through a program that is associated with, as a minimum, Balancing Authority activation (directly or indirectly) to address a reliability issue, or b) the DSM definition should be revised to address three program classifications - reliability-based DSM, economic-based DSM, and programs that may be activated for either reliability or economic purposes. The drafting team should also consider changes to the "... may include, but are not limited to ..." wording so that it does not conflict with the BA-controllable and reliability vs. economic activation issue. Also, the drafting team should write the definition such that the “controllable” DSM programs category is limited to programs that, for reliability purposes, are "sharable" among all LSEs within the Balancing Authority. In the definition of Total Internal Demand the words "DSM Load" should be replaced by the words "served DSM Load" as parts 1.3.1. etc. of Requirement 1 refer specifically (by definition – “metered system”) to total served load.
Individual
Michael Falvo
Independent Electricity System Operator
Yes

1. We do not agree with the proposed changes to the first sentence of the definition of Demand Side Management, in particular the phrase “to request that Demand be reduced”. DSM can be achieved through request or other means such as incentive program or market signal/mechanism. These other means are not requests, and are not achieved through a request. We therefore suggest to change the definition to read: “All activities or programs undertaken by any applicable entity to achieve a reduction in Demand. Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control, and Load as capacity resources.” 2. We do not agree with making the proposed definition of Total Internal Demand a NERC Glossary term. This term is used by MOD-031 only, and is meant to clarify what Demand data was being requested. Its use is limited to this standard only and does not have any widespread impact or application to other standards. We suggest that the proposed term and its definition be confined to this standard only. 3. Requirement R1 is not consistent with the general format or the result-based principle for a standard. The word “may” is not enforceable. If the SDT’s intent is to allow for cases that a PC or BA does not require the demand data, then the requirement can be revised to: The Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data shall develop and issue a data request to the applicable entities in it area, which shall include: 1.1 1.2 etc. 4. Requirement R1: On the previous draft, we commented on the lack of clarity in Part 1.5.3 (now Part 1.4.5) which asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak system conditions. Specifically, we asked whether Part 1.5.3 intends to capture the effective seasonal capacity as opposed to the total capacity for each season. It is unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. The Comment Report appears to be silent on this comment, and we have not seen any material changes made to the standard that provide the needed clarity. We urge the SDT to review and address this comment again. 5. Requirement R1 Parts 1.3.5, 1.4.5 and 1.5.2 includes the text “under the control or supervision” in the currently posed draft. These words are incongruous with the definition of DCLM contained in the Glossary and will only introduce ambiguity. The Glossary definition of DCLM states : Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. The definition does not address DCLM under the supervision of the system operator. 6. Requirement R3: The second sentence is not consistent with the Results-based principles as it does not provide the who, what and how, and the expected reliability outcome. If the SDT wishes to impose a deadline for submission of the demand data, we suggest R3 be revised to: R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request within 75 days of receiving the request. 7. Requirement R4: The sentence “This requirement does not modify an entity’s obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1.” Is unnecessary. This is not a requirement to achieve a reliability objective or reliability outcome and hence is inconsistent with the 10 Benchmarks for a good standard and the Results-based principle. Requirement R1

already holds the applicable entities to complying with the data request; the addition of this sentence in R4 is redundant and unnecessary, and not measurable. We suggest to remove it. Also, the first bullet is not required since R4 already stipulates that "….a written request for the data included in parts 1.3-1.5 of Requirement R1.." There is no need to have the first bullet to once again scope the obligation of the requested entities in providing the data. To a good extent, Part 4.1 can be moved to M4 when the Responsible Entity elects not to provide the data requested under this requirement, for the reasons cited in (1) and (2). Part 4.1 is NOT a requirement, but rather a reason for not complying with the requirement. Measure is a more appropriate place for this provision. 8. On VRFs: Requirement R1 is assigned a MEDIUM VRF. This appears to be inconsistent with the LOW VRF assigned to R1 of MOD-032, which stipulates the requirement for the Planning Coordinator and Transmission Planner to develop the modeling data requirements and reporting procedures. The two requirements appear to be requiring the specification of data and collection procedure required for reliability assessment, yet their VRFs differ by a level. We suggest the SDT to consult the MOD-032 and MOD-033 SDT to confirm the difference based on supporting rationale, or to adjust either VRF to achieve consistency. 9. For R1, there is only one SEVERE VSL for the Planning Coordinator or the Balancing Authority failing to include the entity(s) necessary to provide the data (Part 1.1) or the timetable for providing the data (Part 1.2), but there are no VSLs for the conditions when these entities fail to specify any of Parts 1.3 to 1.5. We suggest to add the VSLs for these conditions to meet the NERC and FERC VSL guidelines. 10. VSLs for R2, R3 and R4: All VSLs for these three requirements consider the delay sin providing data or response to a request. However, the time frames for the three requirements under the same VSL level differ from one another – one starts with a 6-day delay with a 4-day incremental interval; another starts at 75 days with a 6-day incremental interval and the last one starts at 45 days with a 6-day incremental interval. We are unable to locate the rationale/background for VRFs and VSL assignment to find out the basis for the difference. We suggest the SDT to either revise these VSLs to achieve some consistency, or to provide the rationale that justifies their differences.
Group
Dominion
Louis Slade
Dominion agrees with the SDT's decision to create a single standard but still does not support R4 for the same reasons we cited in the previous comment period in which we stated "Dominion suggests removing the phrase "or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner)" from R4. We do not believe any entity other that that entity's Planning Coordinator or Balancing Authority should be allowed to make such as request. If an adjacent Planning Coordinator or Balancing Authority desires this information, they should have to obtain it by requesting from the Planning Coordinator or Balancing Authority within whose area the demand resides.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
(1) Requirement R1 states that the PC or BA "may develop and issue a data request…" In the

last draft, the Requirement read that the PC or BA "shall" instead of "may." Can the SDT explain the reasoning in the change of this language as it appears now the PC and BA may not need to comply with this provision. Additionally, it appears that if the SDT revises the language back to "shall" in a later draft, that such a change would be material and require a full additional ballot, i.e., 45-day period. (2) There are numerous locations where "days" and "annual" are utilized in time requirements throughout the proposed Standard and the VSL/VRF Matrix without defining these terms more accurately. For example, Requirement R1.2 states that "A minimum of 30-days must…;" is this calendar days or business days? Seminole has the same concern with the word "annual." Seminole requests a clarification of these terms such as: calendar days, calendar years, 12 months, etc. (3) If an entity does not provide data as described in Requirement R4.1 and provides reasoning that the requesting entity feels is not a sufficient reason for not disclosing the requested information, what does the SDT believe is the next step the requesting entity should take in order to obtain the requested information from the Applicable Entity? (4) The definition for Demand Side Management in the redline version of the proposed Standard has the acronym "DSM" after "Demand Side Management." The definition in the implementation plan does not have this, yet it still utilizes the acronym in the definition. The definitions should be consistent and DSM should be referenced, unlike how it is not referenced in the implementation plan's version. (5) On page 5 of 16 of the proposed Standard in the second paragraph, first sentence, is "demand" supposed to be capitalized, i.e., is it the Glossary defined term "Demand?" B. VSL/VRF Penalty Matrix Comments (1) Requirement R1 is listed as a Medium VRF and Severe VSL. As stated in our comments for the proposed Standard, the draft Standard states that a PC or BA "may" request such data, however, is not required to do so. With that said, according to this matrix, if an entity does request such data but forgets to include a time line, the penalty is severe (VSL). Seminole does not believe this penalty should be a Severe VSL, but instead should be a Lower VSL, as this is a ministerial act, i.e., placing a due date on the optional data request.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes
Definitions: Revise the definition of DSM as follows: Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to reduce Demand [delete: request that Demand be reduced]. Examples of DSM may include, but are not limited to, PDR and DDR measures, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control, and Load as capacity resources. Demand-related technologies are evolving rapidly and are quickly propogating throughout the industry. As such, we believe that the standard should be designed to accommodate change and increasing DSM market penetration well. We would like to define two broad categories of demand-related technologies which are (1) load reductions, and (2) capacity-related, as follows: Passive Demand Reduction (PDR) – Non-dispatchable, Passive Demand Reduction related technologies reduce peak load and energy consumption. It is anticipated that the Total Internal Demands and Net Energy for Load will reflect these PDR reductions. Typically they are not netted out of the normalized Total Internal

Demand. PDR’s are not under the control or supervision of the System Operator. Dispatchable Demand Reduction (DDR) – Dispatchable Demand Reduction related technologies also reduce peak load and energy consumption, but are are dispatchable. Generally, these DDR resources can be counted as equivalent to installed capacity, and may receive installed capacity credits similar to those provided traditional installed generating resources. DDR’s are under the control or supervision of the System Operator. Requirements: Sub-requirement 1.5 may lead to the use of inconsistent reporting and forecasting methodologies and/or double-counting of demand-related resources. The Planning Coordinator or Balancing Authority should specify an expected reporting and forecasting basis for Total Internal Demand, Net Energy for Load and Demand Side Management data from Applicable Entities in their area, including the reporting of Passive Demand Reduction and Dispatchable Demand Reduction adjustments. Each Applicable Entity should verify that no double-counting exist in its reporting. We, therefore, recommend that Requirement R2 be modified to include a sentence requiring that each Applicable Entity verify that no double-counting exist in its reporting. R2. [INSERT: Each Applicable Entity shall verify that no double-counting of demand-related resources exist in its reporting.] Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority………… We further recommend that either Requirement R3 be modified or that a new requirement R4 be added establishing that the PC or BA have responsibility for verifying that there is no double-counting across LSE’s and DP’s reporting. For example, add a sentence to R3 similar to that above or add a new R4: R3 [INSERT: Each Planning Authority or Balancing Authority shall verify that no double-counting of demand-related resources exists in the reported data.] The Planning Coordinator or the Balancing Authority shall provide the data collected … Or [INSERT: R4. Each Planning Authority or Balancing Authority shall verify that no double-counting of demand-related resources exists between reported data. If double-counting is identified, the Planning Authority or Balancing Authority will work with the reporting Applicable Entities to eliminate any such double-counting.]
Group
Seattle City Light
Paul Haase
Yes
Seattle City Light strongly disagrees with the use of this Standard to define a PA/PC "area" (see footnote associated with R1). The definition of the PA/PC footprint is an ongoing issue that needs to be resolved ultimately in the NERC Rules of Procedure, and Seattle understands that WECC is working on the issue with other regions and NERC. It is inappropriate to use a footnote of a single Standard to create this functional definition, which affects other Standards including PRC-023 and CIP v5 among others and while NERC efforts to address the matter are in progress. Seattle cannot support this Standard until and unless the PA/PC footnote associated with R1 is removed. Seattle also supports, in a general way, the concerns expressed by Florida Municipal Power Agency about the lack of application of P81 principles in creating MOD-031-1, and wonders if a mandatory federal statue is the most appropriate and effective means to collect industry forecast data.
Group

SERC Planning Standards Subcommittee (PSS)
Jim Kelley
Yes
1) The SDT is requested to consider modifying 1.5.4 to read that humidity variations should only be included if the data is collected. Current draft 1.5.4 language: How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,2temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. Suggested draft 1.5.4 language modification: How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,2temperature DELETE: "and humidity variations" and, if applicable, how the assumptions and methods for future forecasts were adjusted. ADD: Humidity variations should be considered if the data is collected by the entity. 2) The SDT is requested to consider modifying R3 to add the term “written” before “request”. Current draft R3 language: R3 The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity. Suggested R3 modification: R3 The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon ADD: “written” request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity. 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.
Individual
David Burke
Orange and Rockland Utilities, Inc.
Agree
Consolidated Edison Co. of NY, Inc.
Individual
Anthony Jablonski
ReliabilityFirst
No
1. The SDT has not effectively addressed the FERC paragraph 1249 directive - ReliabilityFirst does not believe the SDT adequately addressed the Commission directive associated with paragraph 1249 (collection of temperature and humidity data). ReliabilityFirst believes the Commission is looking for the entities to provide the temperatures and humidity so the “model builders” (i.e., the Regional Entities) can normalize all the load data from all the submitting entities on a consistent basis. ReliabilityFirst recommends revising R1, Part 1.3.4 as follows: “Annual peak hour actual Total Internal Demand in megawatts for the prior year [along with associated temperature and humidity data]. Furthermore, the NERC MOD-025-2 (pending FERC

approval) standard has set a precedent in requiring entities to report ambient conditions taken at the time of the generator verification. Even though this data is used for different purposes, the intent to use the weather data to normalize the reported data is the same. 2. Requirement R1 - ReliabilityFirst does not believe the word “may” is appropriate to be used in a Reliability Standard Requirement (i.e., not enforceable). The structure of the requirement makes compliance voluntary and only requires that the data request itself include certain items. Per the NERC Results-Based Reliability Standard Development Guidance document, a performance-based requirement should define a particular reliability objective or outcome to be achieved. A results-based requirement has four components which include “who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?” Furthermore, the NERC Acceptance Criteria of a Reliability Standard document states that “…requirement should identify what functional entity shall do what, under what conditions, for what reliability benefit.” Absent the requirement requiring an applicable entity to do something, this may be problematic in receiving regulatory approval as well. ReliabilityFirst recommends the following for consideration: “Each Planning Coordinator or Balancing Authority may [shall] develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area. The data request shall include:" 3. Requirement R3 and R4 - To further clarify the intent of the SDT, ReliabilityFirst recommends adding the qualifying term “calendar” in front of the term “day” in Requirements R3 and R4. This will eliminate the question of whether it is a calendar or business day requirement. 4. VSL for Requirement R1 - The VSL for Requirement R1 only speaks to failing to include either the entity(s) necessary to provide the data (Part 1.2) or the timetable for providing the data (Part 1.2). ReliabilityFirst notes that there is no mention of an entity failing to meet the intent of Part 1.3, Part 1.4 or Part 1.5. Failure to include these Parts in the data request may result in a possible violation and hence need to be noted in the VSLs. ReliabilityFirst recommends including a Moderate VSL such as: “The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include items in Requirement R1, Parts 1.3, Parts 1.4 or Parts 1.4 in the data request.” 5. VSL for Requirement R4 - The VSL for Requirement R1 does not mention Requirement R4, Part 4.1. ReliabilityFirst recommends the following for consideration for a Moderate VSL: “The Applicable Entity failed to provide a written response to the requesting entity specifying the data that is not being provided and on what basis per Requirement R4, Part 4.1”
Group
Duke Energy
Michael Lowman
Yes
Duke Energy seeks clarification on whether it is implied that Energy Effficiency and Conservation are included in the revised definition of DSM. As written, the definition is sufficiently vague and could be interpreted as only including demand response and/or dispatchable resources. If this definition is intended for only dispatchable resources, Duke Energy suggests that a review of the FERC definition of Demand Response may be useful to the revision of the DSM definition for additonal clarity. Duke Energy believes that the SDT included

Transmission Planner as an applicable entity in MOD-031-1 as a result of a FERC Order 693 directive related to MOD-016-1, which was in force at that time, and its reference to TPL-005 and 006. However, MOD-031-1 does not contain any direct linkage to the TPL standards and therefore should not impact the Transmission Planner. Like the Planning Coordinator, Transmission Planners are recipients of the data to be requested under R1.4 and R1.5 (for building of transmission models and performing planning activities) from the other Applicable Entities included in MOD-031-1. In the NERC Reliability Functional Model, under Function – Transmission Planning, see item 2b Model – Version 5 “Relationships with Other Functional Entities”: “2. Collects information including: a. Transmission facility characteristics and ratings from the Transmission Owners, Transmission Planners, and Transmission Operators. b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.” Based on the present version of the Functional Model, Duke Energy believes is not necessary to include the Transmission Planner as an applicable entity under MOD-031-1. Duke Energy suggests rewording R1 as follows, “R1. Each Planning Coordinator or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area. If issued , the data request shall include: “
Group
Tennessee Valley Authority
Dennis Chastain
Yes
TVA appreciates the efforts of the Standards Drafting Team to develop this replacement standard. As stated in our comments on the initial draft, we believe the MOD-016 through MOD-019, and MOD-021 standards should be retired without a successor. However, it is unclear if the intent of the proposed standard is to facilitate data collection by the registered entities who have a reliabiliy related need to obtain the data, or if the end purpose is to provide data to the Regional Entity. We interpret it to be the latter, in which case section 800 of the NERC Rules of Procedure adequately addresses data collection deemed necessary by NERC and the Regional Entities to perform reliability assessments. Reliability assessments being performed by parties that are not a planner / operator of Bulk Electric System facilities, while informative, do not pose a significant threat to reliability in their absense. Additionally, while the proposed standard addresses the collection of demand and energy data, there is no corresponding standard to collect resource data which is a necessary component for performing reliability assessments. If there is to be a succesor, we agree with the approach to consolidate into a single standard. We submit the following comments on MOD-031-1 should it go forward: We recommend that the consolidated standard for demand and energy data reporting be numbered MOD-016-2 to maintain a legacy with the existing grouping of standards it is designed to retire. We recommend that the focus of the standard be shifted to ensuring that resgistered entities responsible for planning future resources (Transmission Planner and Resource Planner) can request demand and energy related data from registered entities who have access to actual demand and energy data or registered entities that produce

forecasts of future demand and energy data. In addition, Planning Coordinators need to be able to acquire this data for the purpose of their reliability assessments. To that end, we suggest the following changes: For Requirement R1, replace “Planning Coordinator or Balancing Authority” with “Transmission Planner or Resource Planner”. The footnote for “their area” would need to be modified accordingly. For Requirement R1, part 1.1, replace “Transmission Planners” with “Distribution Providers”. For Requirement R2, replace “Planning Coordinator or Balancing Authority” with “Transmission Planner or Resource Planner”. The current R3 should be deleted (data reporting to the Regional Entities and NERC is covered by section 800 of the NERC Rules of Procedure) and replaced with the following: “R3 Each Planning Coordinator may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from the Transmission Planners and Resource Planners in their area.” A footnote explaining “their area” for the PC would need to be added. Sub-bullets 1.1 through 1.5.4 would need to be repeated in this requirement. The current R4 should be deleted and replaced with the following: “R4 Each Transmission Planner and Resource Planner shall provide the data requested by its Planning Coordinator in accordance with the data request issued pursuant to Requirement R3.”
Individual
David Thorne
Pepco Holdings Inc
Agree
PJM Interconnection
Group
JEA
Tom McElhinney
We believe that this standard is purely a data request and should be eliminated in accordance with the P81 project. We also disagree with having internal controls included in a standard.
Individual
Chris Scanlon
Exelon
No
The Exelon companies could support the standard with one important revision. We believe R4 needs to be changed to recognize that LSE's operating in RTO's, may not have access to the data as specified in R1 and should not be subject to requests for data from all entities identified in R4. Our suggestion for changes to R4 are to remove the list of entities who can make a data request of and replace it with the phrase that clarifies that only entities issuing (PC or BA) or who have been subject to a data request per R1 can make a data request of another entity. R4. An entity issuing a data request in R1 shall.....
Group
Florida Municipal Power Agency
Frank Gaffney

FMPA continues to believe that the data collection for long term planning, such as ten year load forecasts, are candidates for P81 treatment, as detailed in our comments during the last posting in September, and as summarized below. MOD-031 is about ten year load forecasts. The use of those ten year load forecasts is limited to adequacy assessments; resource adequacy and transmission adequacy. The Federal Power Act Section 215 specifically excludes standards for adequacy, as quoted below: “(i) Savings Provisions- … (2) This section DOES NOT AUTHORIZE the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with STANDARDS FOR ADEQUACY or safety of electric facilities or services. (3) Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State …” (emphases added) Instead, the ERO’s obligation to Section 215 is for assessments – a separate activity from standards – as quoted below: “(g) Reliability Reports- The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.” The load forecasts that are needed for reliability that are also within the Section 215 construct are operating horizon load forecasts, which are already covered by IRO-010 and TOP-003-2. As such, the goal of gathering long term load forecasts for purposes of assessments should be accomplished through mandatory data requests and not through standards. FMPA recommends that the MOD-016 through -021 standards be retired and replaced with mandatory data requests.
Group
ISO/RTO Standards Review Committee
Gregory Campoli
The SRC would comment that the proposed standard is: internally inconsistent; does not support the concept of mandating a common requirement for all Applicable entities; and addresses an undefined data collection activity rather than a specific reliability gap. Definitions 1. Demand Side Management The SRC does not support the proposed changes to the first sentence of the definition of Demand Side Management, in particular the phrase “to request that Demand be reduced”. DSM can be achieved through request or other means such as incentive program or market signal/mechanism. These other means are not requests, and are not achieved through a request. The SRC recommends that the Demand Side Management definition not be changed. The proposed definition is more broad than the existing definition. Further, in the implementation document, the proposed DSM definition will be applied to several existing standards and standards pending regulatory approval. The impact of any change in the definition of DSM on these standards should be reviewed and assessed prior to this change. 2. Total Internal Demand The SRC does not support the proposed definition of the current NERC Glossary term of Total Internal Demand. This term as used by MOD-031 is only meant to clarify what Demand data was being requested. Its use is limited to this standard only and does not have any widespread impact or application to other standards. We suggest that the proposed explanation be included only as an explanation confined to this standard only and not be used to modify the Glossary term. Under R1: a PC or BA “may” develop and issue a data request, … . While under M1: a PC or BA “shall” have a dated data request, … . R1 and M1 should be coordinated. Suggest changing M1 to “For each developed and issued data request, the PC or BA shall have a dated data request, … . Requirements 3. Requirement R1 R1 is not

consistent with the general format or the result-based principle for a standard. The word "may" is not enforceable. Moreover, under M1: a PC or BA "shall" have a dated data request, … . R1 and M1 should be coordinated. If the SDT's intent is to allow for cases that a PC or BA does not require the demand data, then the requirement can be revised to: The Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data shall develop and issue a data request to the applicable entities in it area, which shall include: 1.1 1.2 etc. 4. On the previous posting, we commented about the lack of clarity in R1: Part 1.5.3 (now Part 1.4.5) which mandated forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak system conditions. Specifically, we asked whether Part 1.5.3 intends to capture the effective seasonal capacity as opposed to the total capacity for each season. It is unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. The Comment Report appears to be silent on this comment, and we have not seen any material changes made to the standard that provide the needed clarity. The SRC again requests the SDT to review and address this comment. 5. R1.3.4 requires peak loads to be normalized for weather. Does this concept have the same meaning for large footprint entities as it did when all entities were concentrated weather-wise in a small area? 6. Requirement R3: R3 is not clear on obligations. What is an applicable Regional Entity; any one of eight? Also, can an RE precipitate a PC or BA data request or can the RE only request data collected by the PC or BA? The second sentence is not consistent with the Results-based principles as it does not provide the who, what and how, and the expected reliability outcome. If the SDT wishes to impose a deadline for submission of the demand data, we suggest R3 be revised to: R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request within 75 days of receiving the request. 7. Requirement R4: The sentence "This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. This sentence is unneceassary because it is not a requirement needed to achieve a reliability objective or reliability outcome and hence is inconsistent with the 10 Benchmarks for a good standard and the Results-based principle. Requirement R1 already holds the applicable entities to complying with the data request making the addition of this sentence in R4 is redundant and unnecessary, and not measurable. The SRC recommends the above referenced sentence be removed. The first bullet is not required since R4 already stipulates that "….a written request for the data included in parts 1.3-1.5 of Requirement R1.." There is no need to have the first bullet to once again scope the obligation of the requested entities in providing the data. Part 4.1 can be moved to M4 when the Responsible Entity elects not to provide the data requested under this requirement, for the reasons cited in (1) and (2). Part 4.1 is NOT a requirement, but rather a reason for not complying with the requirement. Measure is a more appropriate place for this provision. VRFs / VSLs 8. Requirement R1 R1 is assigned a MEDIUM VRF. This appears to be inconsistent with the LOW VRF assigned to R1 of MOD-032, which stipulates the requirement for the Planning Coordinator and Transmission Planner to develop the modeling data requirements and reporting procedures. The two requirements appear to be requiring the specification of data and collection procedure

required for reliability assessment, yet their VRFs differ by a level. We suggest the SDT to consult the MOD-032 and MOD-033 SDT to confirm the difference based on supporting rationale, or to adjust either VRF to achieve consistency. 9. R1 includes only one SEVERE VSL for the Planning Coordinator or the Balancing Authority failing to include the entity(s) necessary to provide the data (Part 1.1) or the timetable for providing the data (Part 1.2), but there are no VSLs for the conditions when these entities fail to specify any of Parts 1.3 to 1.5. We suggest to add the VSLs for these conditions to meet the NERC and FERC VSL guidelines. 10. Requirements R2, R3 and R4 All VSLs for these three requirements consider the delays in providing data or response to a request. However, the time frames for the three requirements under the same VSL level differ from one another – one starts with a 6-day delay with a 4-day incremental interval; another starts at 75 days with a 6-day incremental interval and the last one starts at 45 days with a 6-day incremental interval. We are unable to locate the rationale/background for VRFs and VSL assignment to find out the basis for the difference. We suggest the SDT to either revise these VSLs to achieve some consistency, or to provide the rationale that justifies their differences. General Comments 1. The requirements in this proposed standard constitute a data request. Under paragraph 81, could this standard be retired? If the standard is not retired, R4 should be deleted. If R1.5 should also be deleted. If R1.5 is kept, then it is unclear who determines what information is necessary and in any case, deletion of R1.5.4 is recommended. 2. The requirements reference providing the data to a Region upon request (R3). However, there is no requirement or basis for that request. The SRC believes there are other means (Rules of Procedure) that will serve that need without resorting to writing a standard that requires documentation and proof of compliance. 3. DSM is currently divided into various subdivisions (as recognized within the standard (R1.5.1) by the need to include assumptions and methods for deriving the value). Those differences/subdivions are evidence of a growing and evolving practice. If the SDT wants to define those subdivions it should do so. The concept of allowing each entity to define the same term using different assumptions is inconsistent with the concept of a North American “standard”. The SRC would rather use the Rules of Procedure approach to collect the data and to have a third party evaluate how best to come to a common definition. As written this standard seems to be a fill-in-the-blanks requirement. (Note PJM and CAISO are not included in this set of comments and will submit their own comments)
Individual
Teresa Czyz
Georgia Transmission Corp.
Yes
Comments: R1.3.4 requires weather normalized ACTUAL data and appears to be in conflict with the Background section of this standard concerning adjusting the FORECAST to reflect normal weather. GTC observes that R1.3.4 is actual data and therefore cannot be “weather normalized”. Accordingly, GTC believes the SDT’s intent is to use the ACTUAL data to then “weather normalize” for an appropriate FORECAST as described in the Background section of this standard and the appropriate use of this term should be within R1.4 for “FORECAST” data. Please clarify. The definition for Total Internal Demand is confusing. GTC typically supplies

“demand data” based on meters that are located on the low side of distribution transformers. This metered data includes the Firm Demand, any DSM if applicable and distribution losses. Based on the new definition, GTC would not be able to supply “demand data” that includes “Transmission” losses. We do not own generators and accordingly do not have access to meters at generators to account for “Total Internal Demand” as it is being proposed. Accordingly, being part of an integrated transmission system, it would be difficult to “meter” losses on the Transmission which are due to GTC’s end-use customers. We would not be able to supply metered data for “Total Internal Demand” as the definition is written. In the background section above, it states that a definition for “Net Internal Demand “ was added. There is no such terminology within the standard. However, this term could be more appropriate for demand data from PCs, TPs, LSEs, DPs, etc… which would include “Firm Demand, any DSM Load and distribution losses but would not include transmission losses as described above”. GTC believes that “Net Internal Demand” would relate and be more appropriate to “end-use customers”. As such, GTC recommends the following Definition revisions/additions: GTC would like the drafting team to consider changing “the DSM Load” to “any DSM Load” in the definition(s), since there may be entities with no DSM load and create a separate definition to distinguish demand data which includes transmission losses versus demand data at end-use customers which does not include transmission losses. Total Internal Demand - The Demand of a metered system which includes the Firm Demand, any DSM Load and the Load due to the energy losses incurred in the Transmission and distribution systems. Net Internal Demand - The Demand of a metered system which includes the Firm Demand, any DSM Load and the Load due to the energy losses incurred in the distribution systems. Additionally, GTC believes that since a PC or BA can provide a request to various entity types, then R1 could be enhanced by allowing flexibility of the PC or BA to identify the appropriate type of demand it is seeking from the various entity types (Total Internal Demand or Net Internal Demand). GTC recommends replacing all references of “Total Internal Demand” with “Total Internal Demand or Net Internal Demand” within R1 and applicable sub-requirements. Additionally, GTC recommends incrementing R3, R4, and R5 and creating/inserting a new requirement R3 which states “The type of demand being requested, Total Internal Demand or Net Internal Demand” For further justification of GTC’s position, we offer the following considerations the SDT should ponder: Are “Transmission” losses associated with “transfers”, “loop flows”, or other “inadvertent” flows considered “demand”? If VACAR has a firm transfer to TVA, some of it flows through the Georgia Integrated Transmission System causing losses on the Transmission system but does not serve GTC’s demand and would not be relevant to GTC’s customer demand. Who accounts for those losses in their “demand” numbers? And how or where are they “metered”? Again, the “Total Internal Demand” definition could apply to entities that are capable of metering the data that would include “Transmission” losses and perhaps it is more appropriate for it to be applied to BAs that may have a wide area view of the system, but this would not be appropriate for small entities that are only registered as LSEs or DPs. The Total Internal Demand definition should also note something along the lines of “losses which occur due to transfers, loop flows, etc…. are included in the demand numbers for that entity and may not be attributed to the end use customers in that area.”
Individual

Bill Fowler
City of Tallahassee (TAL)
The City of Tallahassee – Electric Utility (TAL) has reviewed the proposed MOD-031-1 standard (MOD C) and has made the following observations: • R1 – Though the referenced data request may be developed and issued “as necessary”, the language states “The data request shall include …”. This implies that submission of all data items listed is mandatory whether or not the Planning Coordinator or Balancing Authority has determined the need for every data item. The PC or BA should be afforded some latitude to determine those of the listed items needed by changing “shall” to “may”. • R1.3.4 –It is not clear that the process revisions necessary to implement this requirement would be an improvement over the current process. • R1.5.4 – It is not clear the extent to which entities will need to incorporate humidity into the development of forecasts.
Individual
Mahmood Safi
Omaha Public Power District
Yes
The Omaha Public Power District (OPPD) supports the comments provided by the Nebraska Public Power District (NPPD)and the SPP RTO on this Standard. As with NPPD, OPPD views the draft standard’s Requirement 4 as a requirement which opens the door for entities which possess demand data to be questioned on their assessment of another entities credentials pertaining to “demonstrated reliability need “. OPPD references FAC-008-3 as another standard addressing reliability based data. FAC-008-3 covers facility rating data. FAC-008-3 does not contain a similar statement to the one in th proposed standard MOD-031-1, R4. MOD-031 R4 “Each Load Serving Entity, Planning coordinator, Balancing Authority, Transmission Planner or Resource Planner shall within 45 days of a written request for the data included in Parts 1.3 – 1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity.” Contrarily FAC-008-3, R7 and R8 states, R7, “Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities.” R8, “Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s).” OPPD’s opinion is that NERC should adhere to the language established in FAC-008-3 and strike draft MOD-031-1’s R4 requirement.
Individual
Teresa Czyz

Georgia Transmission Corporation
Yes
R1.3.4 requires weather normalized ACTUAL data and appears to be in conflict with the Background section of this standard concerning adjusting the FORECAST to reflect normal weather. GTC observes that R1.3.4 is actual data and therefore cannot be “weather normalized”. Accordingly, GTC believes the SDT’s intent is to use the ACTUAL data to then “weather normalize” for an appropriate FORECAST as described in the Background section of this standard and the appropriate use of this term should be within R1.4 for “FORECAST” data. Please clarify. The definition for Total Internal Demand is confusing. GTC typically supplies “demand data” based on meters that are located on the low side of distribution transformers (12kV and/or 25kV). This metered data includes the Firm Demand, any DSM if applicable and distribution losses. Based on the new definition, GTC would not be able to supply “demand data” that includes “Transmission” losses. We do not own generators and accordingly do not have access to meters at generators to account for “Total Internal Demand” as it is being proposed. Accordingly, being part of an integrated transmission system, it would be difficult to “meter” losses on the Transmission which are due to GTC’s end-use customers. We would not be able to supply metered data for “Total Internal Demand” as the definition is written. In the background section above, it states that a definition for “Net Internal Demand” was added. There is no such terminology within the standard. However, this term could be more appropriate for demand data from PCs, TPs, LSEs, DPs, etc… which would include “Firm Demand, any DSM Load and distribution losses but would not include transmission losses as described above”. GTC believes that “Net Internal Demand” would relate and be more appropriate to “end-use customers”. As such, GTC recommends the following Definition revisions/additions: GTC would like the drafting team to consider changing “the DSM Load” to “any DSM Load” in the definition(s), since there may be entities with no DSM load and create a separate definition to distinguish demand data which includes transmission losses versus demand data at end-use customers which does not include transmission losses Total Internal Demand - The Demand of a metered system which includes the Firm Demand, any DSM Load and the Load due to the energy losses incurred in the Transmission and distribution systems. Net Internal Demand - The Demand of a metered system which includes the Firm Demand, any DSM Load and the Load due to the energy losses incurred in the distribution systems. Additionally, GTC believes that since a PC or BA can provide a request to various entity types, then R1 could be enhanced by allowing flexibility of the PC or BA to identify the appropriate type of demand it is seeking from the various entity types (Total Internal Demand or Net Internal Demand). Especially, since some of the entities would be small (non-vertically integrated) entities that are only registered as LSEs or DPs and would not be able to capture “Transmission” losses as mentioned above. GTC recommends replacing all references of “Total Internal Demand” with “Total Internal Demand or Net Internal Demand” within R1 and applicable sub-requirements. Additionally, GTC recommends incrementing R3, R4, and R5 and creating/inserting a new requirement R3 which states “The type of demand being requested, Total Internal Demand or Net Internal Demand” For further justification of GTC’s position, we offer the following considerations the SDT should ponder: Are “Transmission” losses associated with “transfers”, “loop flows”, or other “inadvertent” flows considered “demand”? If VACAR

has a firm transfer to TVA, some of it flows through the Georgia Integrated Transmission System causing losses on the Transmission system but does not serve GTC's demand and would not be relevant to GTC's customer demand. Who accounts for those losses in their "demand" numbers? And how or where are they "metered"? Again, the "Total Internal Demand" definition could apply to entities that are capable of metering the data that would include "Transmission" losses and perhaps it is more appropriate for it to be applied to BAs that may have a wide area view of the system, but this would not be appropriate for small entities that are only registered as LSEs or DPs. The Total Internal Demand definition should also note something along the lines of "losses which occur due to transfers, loop flows, etc…. are included in the demand numbers for that entity and may not be attributed to the end use customers in that area."
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
The City of Tallahassee – Electric Utility (TAL) has reviewed the proposed MOD-031-1 standard (MOD C) and has made the following observations: • R1 – Though the referenced data request may be developed and issued "as necessary", the language states "The data request shall include …". This implies that submission of all data items listed is mandatory whether or not the Planning Coordinator or Balancing Authority has determined the need for every data item. The PC or BA should be afforded some latitude to determine those of the listed items needed by changing "shall" to "may". • R1.3.4 –It is not clear that the process revisions necessary to implement this requirement would be an improvement over the current process. • R1.5.4 – It is not clear the extent to which entities will need to incorporate humidity into the development of forecasts.
Group
ACES Standards Collaborators
Ben Engelby
Yes
(1) We question why the drafting team decided to modify the NERC Glossary Term for Demand Side Management (DSM). The current definition is clear and there is no need to provide additional clarity. Furthermore, it is used in other NERC standards and we can find no evaluation of the impact created by the change on these standards. This impact must be evaluated before modifying the definition. We also question the need to add a definition for Total Internal Demand, as the standard should state what data could be requested and would not need a definition for this purpose and it conflicts directly with the term as used in the NERC

Long-Term Reliability Assessments and Seasonal Assessments. In these assessments Total Internal Demand is the demand without reducing for DSM. Net Internal Demand is the term used for the demand after removing DSM from the demand. According to the NERC Drafting Team Guidelines, dated April 2009, the guidance states that an SDT "should avoid developing new definitions unless absolutely necessary." There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the phrase rather than trying to obtain stakeholder consensus on the new term. We recommend removing the terms for Total Internal Demand and any proposed changes to DSM. (2) We do not understand how the modified purpose statement in the standard supports reliability. The rationale provided by the SDT is to clearly state the intention of the standard, but we believe that the collection of Demand and energy data is administrative in nature, would qualify for Paragraph 81 retirement, and is better suited for a section 1600 data request. We believe the team needs to reevaluate this purpose of this standard, remove administrative tasks from the requirements, and focus on the activities needed for a more reliable system. We also believe the drafting team should ultimately retire all similar requirements and move them to a section 1600 data request. As reflected in Paragraph 81 criteria, data collection is not well suited for compliance monitoring. A section 1600 data request is mandatory and this would provide the appropriate incentive to ensure data is submitted. There is no need to develop a standard for a data request because the NERC Rules of Procedure already provide equally effective alternate measures to obtain the data. (3) We disagree with several aspects to Requirement R1. In particular, part 1.1 defines the applicable entities, 1.2 creates a timetable for providing data, and 1.3 outlines the scope of the data that an entity would need to provide. Further, the RSAW states that items listed in parts 1.3 through 1.5.4 are optional and are included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard. These aspects of R1 Paragraph 81 criteria and need to be revised. According to P81, requirements for data requests are an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES (criterion A). In addition to criterion A, these data requests are administrative in nature (criterion B1), focus on data collection/data retention (criterion B2), require entities to develop a document that is not necessary to protect BES reliability (criterion B3), require reporting to another entity or party (criterion B4), and require responsible entities to periodically update documentation without an operational benefit to reliability (criterion B5). FERC has stated in previous orders that these concepts should not be the basis for a reliability standard. Based on these reasons, we ask the drafting team to revise the requirement so only activities directly relating to reliability are addressed. (4) Distribution Provider should be removed from Part 1.1. All of the DP's load will already be reported via the LSE or BA. NERC compliance registry

criterion III.a.4 is very clear that DPs “will be registered as a Load Serving Entity (LSE) for all load directly connected to their distribution facilities.” Thus, applicability to DP is not needed. (5) For Requirement R2, the term “Applicable Entities” is not clear. Which applicable entities apply? We believe that it is intended to be those applicable entities that receive the data request pursuant to Part 1.1. However, R2 does not state this clearly so applicability is ambiguous because it could mean all entities in the applicable entity section. We recommend stating “Each Transmission Planner, Balancing Authority, and Load Serving Entity that receives a date request pursuant to Part 1.1 shall...” (6) For Requirement R2, we agree that the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard. However, we continue to believe that R2 also meets P81 criteria because the language in the requirement and the purpose of the standard is to facilitate the sharing of data. (7) For Requirement R3, there should not be a standard for complying with a Regional Entity. The NERC Rules of Procedure outline several methods including a section 1600 data request for regional entities and NERC to request data and may impose sanctions to those entities that fail to comply. There is an equally efficient alternative to achieve the same result that is being sought in R3. We recommend striking the requirement. (8) For Requirement R4, we do not see the need for this requirement and the timelines are arbitrary. As stated above, the items in this requirement meet P81 criteria. For instance, listing the data that could be requested, the neighboring entities that could request data and the conditions for when a data provider could refuse to provide the data are all administrative tasks that do not benefit or protect the reliable operation of the BES. We recommend striking this requirement. (9) For Requirement R4, an LSE will never have a reliability-related need to request the data from another LSE. We believe such a request could violate the FERC standard of conduct. If the entire requirement is not removed, the section authorizing an LSE to request data from another LSE should be struck. (10) In regard to the VSLs/VRFs, since we disagree with the approach of the drafting team’s modified requirements, we also disagree with the corresponding VSLs and VRFs. (11) Thank you for the opportunity to comment.
Group
SPP Standards Review Group
Robert Rhodes
The information on the Effective Date is provided twice, once in front of the standard and then again in the standard itself. We suggest deleting one of them, preferably the first one. The changes made to the Purpose are an improvement which makes the statement really hit home on what the intent of the standard is. In the first sentence of the second paragraph of the Background information, the term ‘demand’ is used. Shouldn’t this term be capitalized? The clarification that was intended with the revised definition of Demand-Side Management and the introduction of Total Internal Demand has missed the mark. As such, we would recommend deleting Total Internal Demand and reverting back to the DSM definition provided in the previously posted version of the standard. It reads: ‘The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use.’ In Requirement 1.4.4 the standard asks for Net Energy for Load for ten years. In Requirement 1.4.5 the standard asks for Interruptible Load and Direct Control Load Management for up to

ten years. Shouldn’t they have the same time requirement? Why would they be different? We recommend deleting R4. Requests for demand data should be coordinated through the PC and should not be a mandatory requirement under the standard. There are concerns surrounding the determination of whether a requesting entity has a valid reliability reason for obtaining the data. Additionally, this creates opportunities for inconsistency when auditors are reviewing evidence supplied for this requirement. We note that when timing requirements are referenced in the VSLs, there is what appears to be a common usage of a 6-day increment. Why 6 days? This standard operates on a long-term planning horizon and doesn’t really justify such a tight tolerance. Why couldn’t it be 15 or 30 days for that matter? We recommend that the drafting team replace references to the Bulk Power System (BPS) in the White Paper with Bulk Electric System (BES).
Individual
Angela P Gaines
Portland General Electric Co
Agree
WECC's position based on their position paper.
Group
Bonneville Power Administration
Andrea Jessup
Yes
BPA suggests a definition be added to the Definitions of Terms Used in Standard section for the term “Net Energy to Load”.
Individual
Catherine Wesley
PJM Interconnection
PJM very much appreciates the drafting team’s work which resulted in the present draft. We appreciate the language included in R1. PJM does have a concern with the definition for Total Internal Demand as written such that it will result in a negative ballot for the draft. We urge the drafting team to revise the definition with the following language: Total Internal Demand: The Demand of a metered system which includes the Firm Demand, the DSM Load under the control or supervision of the System Operator and the Load due to the energy losses incurred in the Transmission and distribution systems. PJM also recommends revising the language in R4 to remove the specific entities issuing or being required to respond to a data request. We propose the following language: Any entity issuing or subject to a data request in R1 shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity’s obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1.
Group

Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
Because requests are likely to be made of small DPs and LSEs, AECI believes that reporting of weather normalized demand and demand side load management factors are unreasonable. Effects of Direct Load Management programs and Demand Side Management have been historically difficult to ascertain and apparently degrade over time. Forcing these entities to produce weather-normalized load forecasting data could be more burdensome than simply providing their data. Forcing weather data is also unnecessarily burdensome although it might be very reasonable to request what national weather service weather-reporting stations and weather forcecasting locals they monitor for their own internal load predictions. AECI believes that optional choices for reporting might be reasonable: 1) actual data, without the attendant esplanations, or 2) weather-normalized data, along with the attendant explanations. However forecast DSM might be reasonable as the smaller DPs or LSEs could simply report the expected level of performance when they first installed the systems.

Additional comment submitted:

California ISO
Richard Vine

The California ISO has a member on this drafting team. Based on the significant number of concerns identified by WECC and by the other ISO/RTOs, the ISO votes NO and will continue to participate on the drafting team to work to overcome the concerns raised in order to get this standard right for the industry.

NERC

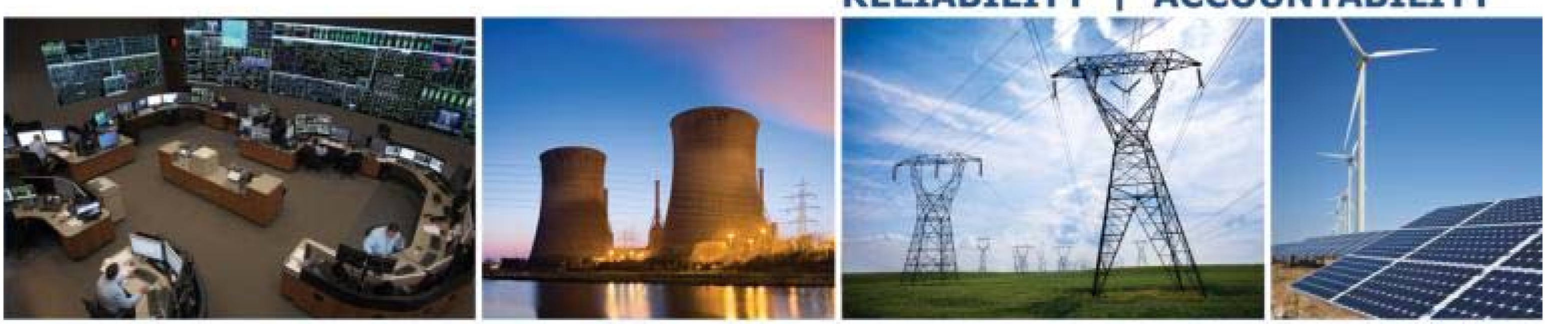
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2010-04 Demand Data

February, 2014

RELIABILITY | ACCOUNTABILITY



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Atlanta, GA 30326

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Introduction

The Project 2010-04 standard drafting team (SDT) thanks all commenters who submitted comments on MOD-031-1. The standard was posted for a 45-day formal comment period from October 9, 2013 through November 22, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 43 sets of responses, including comments from approximately 144 different people from approximately 94 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 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

Purpose

The MOD-031-1 SDT appreciates industry's comments on the MOD-031-1 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if an additional comment period and ballot are needed. The following pages are a summary of the comments received and how the SDT addressed them.

ROP Section 800/1600 Data Request

A few commenters stated that the existing MOD C standards (MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, MOD-020-0 and MOD-021-1) should be retired. Commenters argued that the data could be collected by NERC and the Regional Entities through data requests issued pursuant to Section 800 or Section 1600 of NERC's Rules of Procedure. The SDT concluded that a standard was necessary for two reasons. First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.[2] The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners to obtain the data from a neighboring entity. Replacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes. The SDT concluded that because there is a reliability need for Planning Coordinators and Balancing Authorities to obtain demand data for their own reliability purposes and for data sharing between registered entities, a standard was appropriate.

NERC Glossary Term "Demand Side Management"

A couple of commenters asked the SDT not to change the NERC Glossary term Demand Side Management (DSM). The intent in modifying the definition, however, was to respond to a FERC directive. The SDT has revised the definition to provide the understanding that DSM can be achieved through a request or other means such as incentive programs or a market signal/mechanism.

NERC Glossary Term Total Internal Demand

Some commenters asserted that the standard should be more specific as to what Demand data can be requested. In response to their concerns, the SDT developed a new defined term, Total Internal Demand, to clarify the type of data that may be requested. The SDT made minor modifications to this definition to provide additional clarity. Upon acceptance of this standard, this definition will be included in the NERC Glossary of Terms.

Purpose Statement

A commenter stated that the purpose did not support reliability. The SDT modified the purpose statement to further clarify the reliability purpose of the standard. Specifically, the SDT modified the purpose statement to

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[2] Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities has the authority to collect the necessary data from all applicable registered entities.

reflect that the standard was needed to provide authority for entities that may otherwise lack the authority to collect the specific reliability data.

Applicability Section

One commenter questioned why the Transmission Planner would be subject to this standard. The SDT included the Transmission Planner in response to a FERC directive. The SDT concluded that the Transmission Planner should be included in the standard in the event that it would need to request data from an adjacent area (Requirement R4).

Requirement R1

Several commenters expressed concern with the SDTs use of the term “may” within the requirement. The SDT agreed and modified the requirement to use the language suggested by a few of the commenters. The requirement now reads “Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data shall develop and issue a data request to the applicable entities in their area.”

A few commenters questioned if the SDT was proposing a calendar year for the data. The SDT did mean a calendar year and has modified the requirement to include the term “calendar year”.

Some of the commenters questioned the SDTs attempt to define the PC/BA area within a footnote. The SDT modified the language in the requirement and removed the footnote.

A couple of commenters stated that they were unsure of the value of collecting weather normalized data. The SDT is responding to a FERC directive to collect this data. However, the SDT modified the requirement to clearly identify that only those entities whose Demand varies due to weather-related conditions would need to provide weather normalized data.

Commenters questioned if there should be an “exemption” if an entity does not have access to the data (i.e., humidity). As noted above, the SDT modified the requirement to clearly identify that only those entities whose Demand varies due to weather-related conditions would need to provide weather normalized data.

Commenters questioned whether Part 1.4.5 intended to capture the effective seasonal capacity as opposed to the total capacity for each season. They felt it was unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. The SDT modified the requirement to clarify the intent of the requirement.

Requirement R2

The SDT modified Requirement R2 to clearly identify applicable Entities that would be responsible for responding to a data request.

Commenter questioned whether the requirements should state “in writing”. The SDT believes that the measure covers this issue. The measure clearly states the evidence would be either in “hardcopy or electronic” format.

Requirement R3

One commenter felt that Requirement R3 was putting a requirement on the Regional Entity (RE). The SDT is not requiring anything of the RE. The requirement only mandates that an entity to respond to a request from its RE.

A couple of commenters stated that the second sentence in the requirement it did not provide any additional clarity. The SDT agreed and modified the requirement to remove this sentence.

Commenter questioned whether the requirements should state “in writing”. The SDT believes that is the measure covers this issue. The measure clearly states the evidence would be either in “hardcopy or electronic” format.

Requirement R4

A few commenters disagreed with having an LSE or DP be compliant with Requirement R4. The SDT agreed in part and has modified the requirement. The SDT revised the requirement to remove the LSE and DP from those entities that can request data but they would be required to provide data on request.

A couple of commenters asserted that the following sentence was unnecessary because it is not a requirement needed to achieve a reliability objective or reliability outcome and hence is inconsistent with the 10 Benchmarks for a good standard and the Results-based principle: “This requirement does not modify an entity’s obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1.” The intent of this statement is to clarify that Requirement R4 does not override an entity’s obligation from complying with Requirement R2.

Some commenters disagreed with allowing an entity, other than the PC or BA, to have the opportunity to request data from its neighbors. The SDT disagrees with the commenters and points out that this opportunity exists in the present FERC approved standards. The SDT believes that there could be instances when a neighboring entity would have a reliability related need for the data.

Violation Severity Levels (VSLs)

There were comments regarding concerns with the VSLs. All VSLs have been reviewed and modified as necessary to ensure proper alignment with the requirements.

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. The SAR and supporting package were posted for comment (July 2013).
2. First posting of the draft standard for a 45-day comment period and parallel ballot (July/August 2013).
3. Second posting of the draft standard for a 45-day comment period and parallel ballot (October/November 2013)

Description of Current Draft

This is the third posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
45-day Comment Period with Parallel Ballot	February-March 2014
Final ballot	April 2014
BOT adoption	May 2014

Effective Dates

MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Total Internal Demand: The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

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: Demand and Energy Data**

2. **Number:** **MOD-031-1**

3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. **Applicability:**

   4.1. **Functional Entities:**

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "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 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform the studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they must identify the entities to provide the data (Applicable Entity in part 1.1), and that the entities providing the data must know what they are to provide (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions [e.g., temperature, humidity or wind speed], or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in their area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary, about:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak load forecast compares to actual load for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

Rationale for R2: This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

R2. Each Applicable Entity, identified in the data request, shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

Rationale for R3: This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity within 75 days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authoirty, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric Sysytem, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and

- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

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	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part

			Requirement R1, but did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to

			Requirement R2, but did so after 75 days from the date of request but prior to 81 days from the date of the request.	Requirement R2, but did so after 80 days from the date of request but prior to 86 days from the date of the request.	Requirement R2, but did so after 85 days from the date of request but prior to 91 days from the date of the request.	91 days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

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. The SAR and supporting package were posted for comment (July 2013).
2. First posting of the draft standard for a 45-day comment period and parallel ballot (July/August 2013).
3. Second posting of the draft standard for a 45-day comment period and parallel ballot (October/November 2013)

Description of Current Draft

This is the third posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
45-day Comment Period with Parallel Ballot	February-March 2014
Final ballot	April 2014
BOT adoption	May 2014

Effective Dates

MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to achieve a reduction in~~request that~~ Demand~~ be reduced~~. ~~Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control, and Load as capacity resources.~~

Total Internal Demand: The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable ~~the~~ DSM Load and the Load due to the energy losses incurred within the boundary of the metered~~Transmission and distribution~~ system~~s~~.

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: Demand and Energy Data**
2. **Number:** **MOD-031-1**
3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data~~ for the collection of Demand and energy data to support reliability studies and assessments~~.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "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 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that ~~the purpose of this standard may be carried out ~~various forms of historical and forecast D~~d~~emand and energy data and information is~~must be~~ available to the parties that perform the studies and assessments, authority is needed to collect the applicable data ~~needed to ensure the adequacy of the Bulk Electric System (BES) and to be able to validate past events. The fundamental test for determining the adequacy of the BES is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 forecast (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions~~.

The collection of D~~d~~emand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – ~~will ultimately~~ enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they must identify the entities to provide the data (Applicable Entity in part 1.1), and that the entities providing the data must know what they are to provide (parts 1.3 – ~~R~~ 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions [e.g., temperature, humidity or wind speed], or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

R1. Each Planning Coordinator or Balancing Authority that identifies a need ~~may develop and issue a data request, as necessary,~~ for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data ~~from~~ shall develop and issue a data request to the applicable entities in their area.~~[1]~~ The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar~~-~~ days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly ~~Total Internal~~ Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak~~-~~ hour ~~actual Total Internal~~ Demands in megawatts for the prior calendar year.

~~1.3.1.1.~~**1.3.2.1.** If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

~~1.3.2.~~**1.3.3.** Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

~~Annual peak hour weather normalized actual Total Internal Demand in megawatts for the prior year.~~

~~1.3.3.~~**1.3.4.** Monthly and annual peak hour ~~deployed and realized~~ controllable and dispatchable Demand Side ~~Interruptible Load and Direct Control Load~~ Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

~~[1] For the Balancing Authority, "their area" encompasses their Balancing Authority Area as defined in the NERC Glossary of Terms. For the Planning Coordinator, "their area" encompasses the facilities for which the Planning Coordinator coordinates and integrates transmission facilities, service plans, resource plans, and protection systems.~~

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. ~~Peak hour f~~~~Forecasts of program t~~Total and available peak hour forecast of ~~Interruptible Load and~~ controllable and dispatchable Demand Side Management~~Direct Control Load Management~~ (summer and winter), in megawatts, under the control or supervision of the System Operator for ~~up to~~ ten calendar years into the future~~, as requested, for summer and winter peak system conditions~~.

1.5. A request to provide any or all of the following~~a~~ summary explanations, as ~~of the following, if~~ necessary, about:

1.5.1. The assumptions and methods used in the development of aggregated P~~p~~eak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management~~Interruptible and Direct Control Load Management~~ under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

~~**1.5.4.**~~**1.5.5.** How the peak load forecast compares to actual load for the prior calendar year with due regard to any relevant weather-related~~controllable and dispatchable Demand Side Management and load,~~[2] ~~temperature and humidity~~ variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

[2] ~~For the purpose of this standard, the term "controllable load" means both Interruptible Load and Direct Control Load Management as referenced in FERC Order 693 Paragraph 1267.~~

Rationale for R2: This requirement will ensure that entities identified in Requirement R1, as~~that are~~ responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 ~~4~~- 1.5~~6~~ of Requirement R1.

R2. Each Applicable Entity, identified in the data request, shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning~~-~~]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data ~~requested~~ in accordance with Requirement

> Rationale for R3: This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity ~~upon request~~ within~~. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than~~ 75 days of receiving~~from the date it received~~ a~~the data~~ request for such data, unless otherwise agreed upon by the parties~~from the Regional Entity~~. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authoirty~~entity identified by the Regional Entity in its data request~~, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

> Rationale for R4: This requirement will ensure that the Applicable Entity will make~~provide~~ the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities ~~a~~ (~~Load Serving Entity,~~ Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R4. Any Applicable Entity~~Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner~~ shall, in response to~~within 45 days of~~ a written request for the data included in parts 1.3-1.5 of Requirement R1 from a~~ny other Load Serving Entity,~~ Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated ~~reliability~~ need for such data in order to conduct reliability assessments of the Bulk Electric Sysytem, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity ~~is not required to~~: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested ~~any~~ data ~~data not~~ within 45 calendar days of the written request, subject to part 4.1 of this requirement ~~the scope of part 1.3-1.5 of Requirement R1~~; and
- shall not be required to alter the format in which it maintains or uses the data.~~; andor~~
- ~~provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.~~

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity ~~Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner~~ identified in Requirement R4~~,~~ shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

~~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	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5~~4~~ OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4~~5~~ OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4~~5~~ OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4~~5~~ OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part

			Requirement R1, but did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to

			Requirement R2, but did so after 75 days from the date of request but prior to 81 days from the date of the request.	Requirement R2, but did so after 80 days from the date of request but prior to 86 days from the date of the request.	Requirement R2, but did so after 85 days from the date of request but prior to 91 days from the date of the request.	91 days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

> **Demand Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
>
> **Total Internal Demand:** The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

The defined term "Demand Side Management" is incorporated in the NERC approved standards listed in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand Side Management," it is not anticipated that the proposed revision will have any effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

MOD-031-1 shall become effective as follows:

The first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term “Demand-Side Management”

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term “Demand-Side Management”

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

Demand Side Management: All activities or programs undertaken by any applicable entity to achieve a reduction in ~~request that~~ Demand~~ be reduced~~. ~~Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control and Load as capacity resources.~~

Total Internal Demand: The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable~~the~~ DSM Load and the Load due to the energy losses incurred within the boundary of the metered~~Transmission and distribution~~ system~~s~~.

The defined term “Demand Side Management” is incorporated in the NERC approved standards listed in Attachment 1 of this document. After reviewing the standards incorporating the term “Demand Side Management,” it is not anticipated that the proposed revision will have any effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

MOD-031-1 shall become effective as follows:

The first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Demand-Side Management"

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term "Demand-Side Management"

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

Unofficial Comment Form

Project 2010-04 Demand Data (MOD C)
MOD-031-1 (Demand and Energy Data)

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. ET **Thursday, April 10, 2014**.

If you have questions please contact Darrel Richardson at darrel.richardson@nerc.net or by telephone at 609-613-1848.

The project page may be accessed by clicking here.

Background Information

The Project 2010-04 Demand Data Standard Drafting Team posted a second draft of the Standard MOD-031-1 (Demand and Energy Data) for comment from October 9, 2013 to November 22, 2013. The drafting team has revised the standard based on stakeholder comments and suggestions that the drafting team considered appropriate. The following is a summary of changes the drafting team has made:

- Modified the definition for Demand Side Management to provide additional clarity
- Modified the definition for Net Internal Demand to provide additional clarity
- Modified the Purpose Statement to clearly state the intention of the standard
- Modified Requirements R1 through R4 to provide clarity:
- Modified the VSLs to align with the modified requirements

This posting solicits comment on the revised MOD-031-1 standard. The standard responds to FERC Order 693 and lessons learned from compliance history.

Questions on MOD-031-1

1. **Please provide any issues you have on this draft of the MOD-031-1 standard and a proposed solution.**

Comments:

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Demand Data		
Date Submitted:	July 18, 2013		
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC		
Telephone:	609-613-1848	E-mail:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.
Purpose or Goal (How does this request propose to address the problem described above?):
The pro forma standard consolidates the reliability components of the existing standards.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 693, remove ambiguity from the requirements, and incorporate lessons learned.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
An informal development ad hoc group is presenting a pro forma standard that consolidates the existing MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1 into a single standard. The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. The pro forma standard requirements are currently placed within a new standard, MOD-031-1.
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.)
Detailed description of this project can be found in the Technical White Paper of this SAR submittal package.

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.

Reliability Functions		
☒	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.
☒	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

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.
☐	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
MOD-001-1a	Available Transmission System Capability

Related Standards	
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None

Regional Variances	
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-031-1
July 3, 2013

Introduction

The NERC Compliance department (Compliance) worked with the 2010-04 Demand Data standard drafting team (SDT) to review the proposed standard MOD-031-1. The purpose of the review was to discuss the requirements of the pro forma standard 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-031-1 Questions

Question 1

In Requirement R2, will the auditor verify 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 sharing of data, the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard.

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

B. Requirements and Measures

R1. The Planning Coordinator or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Loads and Demande Side Management data from applicable entities in their area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts (MW) for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management in megawatts for the prior year.

1.4. A request to p[rovide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load[1], temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to

[1] For the purpose of this standard, the term "controllable load" shall refer to both interruptible load and direct control load management as referenced in FERC Order 693 Para 1267.

Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or
- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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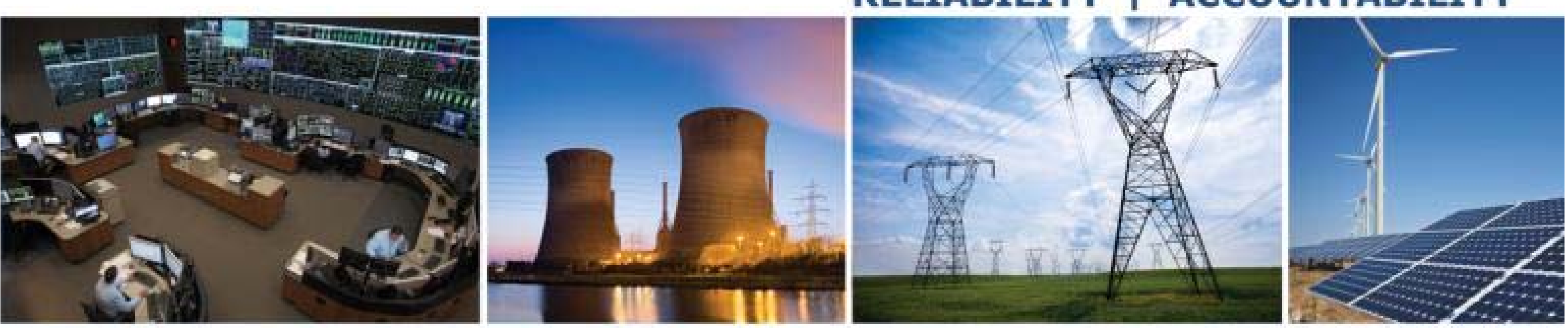
White Paper on the MOD C Standards

MOD-016, MOD-017, MOD-018, MOD-019, and MOD-021

February 14, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the “MOD C” standards), were approved in the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 provides for the documentation of the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 provides for the collection of interruptible demands and direct control load management.
- MOD-020-0 addresses the need to provide interruptible demands and direct control load management data to System Operators and Reliability Coordinators.
- MOD-021-1 provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC’s Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC’s Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

A pure data reporting standard would be a candidate for retirement under Paragraph 81. During the review of the requirements in the current standards, it was not clear whether every Planning Authority (PA) and Balancing Authority (BA) had authority to collect this data from all registered entities in their PA/BA area. Since the data being collected has a reliability purpose in the development of future reliability assessmentseach PA/BA needs the authority to collect this data. In order to specify the scope and limitations of the data collection authority, there was a consolidation of the remaining five MOD C standards into a single standard. The consolidation effort was supported by the industry as the group conducted informal development outreach. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

As detailed below, this document discusses the outstanding directives from FERC Order No. 693 and identifies the applicable requirements in standard MOD-031-1 Demand and Energy Data that address each directive.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of collecting data used in reliability assessments. This document outlines the next generation of these standards and proposes to combine the reliability components of this package of standards into one standard. The remaining requirements in this package would either be retired as administrative or captured as instructional or explanatory in a white paper.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how NERC is addressing each of the outstanding FERC directives assigned to these FERC-approved standards. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

Technical Discussion

The fundamental test for determining the adequacy of the bulk power system (BPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand projections requires coordination and collaboration between Planning Authorities/Planning Coordinators, Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts—as well as the supporting methods and assumptions used to develop these forecasts—will ultimately enhance the reliability of the BPS. Consistent documenting and information-sharing activities will also improve the efficiency of planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and Demand-Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

A second alternative to addressing data requirements in the absence of a standard is the implementation of either a Section 800 or Section 1600 data request. The SDT concluded that a standard was necessary for two reasons. First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.[1] The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Tranmission Planners to obtain the data from a neighboring entity. Replacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes. The SDT concluded that because there is a reliability need for Planning Coordinators and Balancing Authorities to obtain demand data for their own reliability purposes and for data sharing between registered entities, a standard was appropriate.

The recommended option of modifying the existing standards to remove the ambiguity and address the FERC directives solves the issues identified with the first two options. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada. The informal development effort recommended this approach and the standard drafting team has accepted this approach for the development of a consolidated standard.

[1] Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities has the authority to collect the necessary data from all applicable registered entities.

Outstanding FERC Directives

There are 11 outstanding FERC directives from Order 693. Each of the directives was extensively reviewed and discussed in detail by the standard drafting team

In the Paragraph 81 initiative of its March 15, 2012 order accepting a new enforcement mechanism,[2] FERC invited the ERO to identify possible requirements that have little to no effect on reliability that could be removed from the NERC Reliability Standards. The standard drafting team took the information from the FERC order into consideration when it discussed the directives related to the MOD C initiative.

Para 1232

Supported by many commenters, **the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans**. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. **Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.**

Consideration of Directive

With regard to the first directive, the Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Regarding the second directive, a modified definition for Demand-Side Management (DSM) is proposed which includes the language directed by the Commission. The drafting team believes this is an equally effective definition. It now reads:

> **Demand-Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

Consideration of Directive

Weather effects actual demand. Among other things, space conditioning (air conditioning, heat pumps and other heating loads) influences actual demand values significantly. The standard drafting team believes the important consideration in this directive is to be able to adjust the actual demand data to account for weather effects, so a "meaningful comparison

[2] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

with forecast values" can be made. Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3.2.1). Further, Requirement R1 part 1.5.5 also requires that a comparison be made. Each load forecasting entity can decide which aspects of weather need to be measured so as to adjust the actual demand for the difference in demand due to the differences between forecast weather conditions and actual weather conditions (weather normalization). Reporting weather normalized actual demand data instead of the temperature and humidity data also addresses the concerns in the paragraph 1250 directive below. Entities forecasting demand that is not weather sensitive will not be required to provide data that has no impact on their forecast or actual demand data.

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

Requirement R1 part 1.3.2.1 of the proposed standard MOD-031-1 Demand and Energy Data asks for weather normalized data. If the load is not sensitive to weather, then the weather normalized and actual load will be the same.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.5.5).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.5).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

The Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain if certain data is unavailable and why the entity believes the lack of data does not materially impact reliability.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain why the entity believes their forecast method does not materially impact reliability.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

Requirement R1 parts 1.3.5 and 1.4.5 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must report DSM data and provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 parts 1.5.2, 1.5.3 and 1.5.4).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The standard drafting team accepted this consolidation approach and modified the requirements to ensure data will be made available to support assessments of the reliability of the Bulk Power System.

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NORTH AMERICAN ELECTRIC
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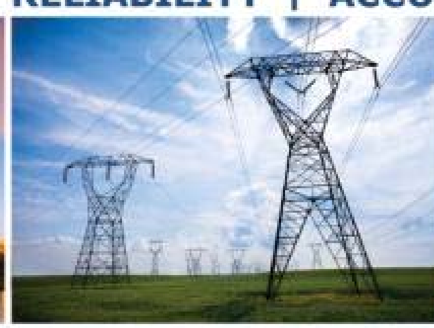
White Paper on the MOD C Standards

MOD-016, MOD-017, MOD-018, MOD-019, and MOD-021

February 14, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the “MOD C” standards), were approved in the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 provides for the documentation of the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 provides for the collection of interruptible demands and direct control load management.
- MOD-020-0 addresses the need to provide interruptible demands and direct control load management data to System Operators and Reliability Coordinators.
- MOD-021-1 provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC’s Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC’s Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

~~Although a~~A pure data reporting standard would be a candidate for retirement under Paragraph 81.~~,~~ During the review of the requirements in the current standards, it was not clear whether every Planning Authority (PA) and Balancing Authority (BA) had authority to collect this data from all registered entities in their PA/BA area. Since the data being collected has a reliability purpose in the development of future reliability assessments~~ for resource adequacy.~~each PA/BA needs the authority to collect this data. In order to specify the scope and limitations of the data collection authority, there was a ~~It was decided to present a pro forma standard that~~ consolidation~~es~~ of the remaining five MOD C standards into a single standard.~~,~~ The consolidation effort ~~which~~ was supported by the industry as the group conducted informal development outreach. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

As detailed below, this document discusses the ~~MOD C informal ad hoc group discussed the~~ outstanding directives from FERC Order No. 693 ~~and, through the informal development, provided a resolution to address each one~~and identifies the applicable requirements in standard MOD-031-1 Demand and Energy Data that address each directive.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of collecting data used in ~~the analysis of resource needs~~reliability assessments. This document outlines the next generation of these standards and proposes to combine the reliability components of this package of standards into one standard. The remaining requirements in this package would either be retired as administrative or captured as instructional or explanatory in a white paper.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how NERC is addressing each of the outstanding FERC directives assigned to these FERC-approved standards. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. ~~The contents of this paper are intended to assist the standard drafting team (SDT) assigned to MOD C and industry stakeholder participants with background information to move this standard package through the formal development process.~~ Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

Technical Discussion

The fundamental test for determining the adequacy of the bulk power system (BPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand projections requires coordination and collaboration between Planning Authorities/Planning Coordinators, Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts—as well as the supporting methods and assumptions used to develop these forecasts—will ultimately enhance the reliability of the BPS. Consistent documenting and information-sharing activities will also improve the efficiency of planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and Demand-Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

A second alternative to addressing data requirements in the absence of a standard is the implementation of either a Section 800 or Section 1600 data request. The SDT concluded that a standard was necessary for two reasons. First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.[1] The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Tranmission Planners to obtain the data from a neighboring entity. Replacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes. The SDT concluded that because there is a reliability need for Planning Coordinators and Balancing Authorities to obtain demand data for their own reliability purposes and for data sharing between registered entities, a standard was appropriate.

~~This approach, while effective, has a number of disadvantages. First, some Canadian provinces are not subject to FERC rule, which makes it more difficult for NERC to enforce an 800 or 1600 data request. The second issue is with entities within the continental United States. The 800 or 1600 data request is not mandatory and does not provide a mechanism to compel participation other than pursuing federal action under Section 215 of the Federal Power Act. In addition, using either of these approaches does not provide a mechanism for other LSEs, DPs, BAs or TPs to obtain the data from a neighboring entity.~~

The recommended option of modifying the existing standards to remove the ambiguity and address the FERC directives solves the issues identified with the first two options. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada. The informal

[1] Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities has the authority to collect the necessary data from all applicable registered entities.

development effort ~~resulted in the~~ recommended~~ation~~ this approach and the standard drafting team has accepted this approach for the development of a consolidated standard.~~ and has provided a draft version that combines the five existing standards into a single, comprehensive, and clear standard with three requirements.~~

Outstanding FERC Directives

There are 11 outstanding FERC directives from Order 693. Each of the directives was extensively reviewed and discussed in detail ~~during the informal development stage, and summaries of the discussions can be found below. The ad hoc group~~by the standard drafting team ~~extensively reviewed each of the directives with consideration of where the existing standards are today, where the group landed with the pro forma standard following its extensive industry outreach, and how the group addressed each directive.~~

In t~~T~~he ~~“~~Paragraph 81 initiative of its~~,” which was issued by FERC in their~~ March 15, 2012 order accepting a new enforcement mechanism,[2] FERC invited the ERO to identify possible requirements that have little to no effect on reliability that could be removed from the NERC Reliability Standards. The ~~ad hoc group~~standard drafting team took the information from the FERC order into consideration when it discussed the directives related to the MOD C initiative.

Para 1232

Supported by many commenters, **the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans**. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO’s definition in the glossary of DSM as “all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use.” Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. **Specifically, we direct the ERO to add to its definition of DSM “any other entities” that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.**

Consideration of Directive

With regard to the first directive, ~~the ad hoc group is recommending that~~ the Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Regarding the second directive, ~~the ad hoc group is proposing~~ a modified definition for Demand-Side Management (DSM) is proposed which includes the language directed by the Commission. ~~However, t~~The ~~group felt~~drafting team believes this is ~~that the FERC proposed definition needed further clarity, so they modified it in~~ an equally effective ~~and efficient manner~~definition. It now reads:

> **Demand-Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican’s observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel’s proposal that the standard be revised to include only the generic term “peak producing weather conditions” because it is too generic for a mandatory Reliability Standard.

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[2] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

Consideration of Directive

Weather effects actual ~~load~~demand. Among other things, space conditioning (~~A~~air conditioning, heat pumps and ~~electric~~ other heating loads) influences actual ~~load~~ demand values significantly.

~~The informal ad hoc group developed Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data. Requirement R1 now requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3.4).~~The standard drafting team believes the important consideration in this directive is to be able to adjust the actual demand data to account for weather effects, so a "meaningful comparison with forecast values" can be made. Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3.2.1). Further, Requirement R1 part 1.5.5 also requires that a comparison be made. Each load forecasting entity can decide which aspects of weather need to be measured so as to adjust the actual demand for the difference in demand due to the differences between forecast weather conditions and actual weather conditions (weather normalization). Reporting weather normalized actual demand data instead of the temperature and humidity data also addresses the concerns in the paragraph 1250 directive below. Entities forecasting demand that is not weather sensitive will not be required to provide data that has no impact on their forecast or actual demand data.

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

~~The informal ad hoc group discussed this issue at length and decided that there should not be an exemption. The group believes that if the load is not weather-sensitive then an explanation will be provided (Requirement R1 part 1.5.4), which will accomplish the same objective as providing an exemption.~~Requirement R1 part 1.3.2.1 of the proposed standard MOD-031-1 Demand and Energy Data asks for weather normalized data. If the load is not sensitive to weather, then the weather normalized and actual load will be the same.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

~~The informal ad hoc group developed~~ Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data~~. The requirement~~ now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.5.5).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

~~The informal ad hoc group developed~~ Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data~~. The requirement~~ now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.~~4~~5).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

~~The informal ad hoc group, as a result of its informal outreach, is recommending that t~~The Transmission Planner has be~~e~~en added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

~~The informal ad hoc group discussed this issue at length with industry participants during informal outreach and decided that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.~~The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain if certain data is unavailable and why the entity believes the lack of data does not materially impact reliability.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

~~The informal ad hoc group discussed this issue at length during its outreach and concluded that there should not be an exemption. The group believes that all load data should be reported to accurately model the Bulk Power System.~~ The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain why the entity believes their forecast method does not materially impact reliability.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

~~The SDT developed~~ Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data~~. The requirement~~ now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

~~The informal ad hoc group developed~~ Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data~~. The requirement~~ now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

~~The informal ad hoc group developed~~ Requirement R1 parts 1.3.5 and 1.4.5 of the proposed standard MOD-031-1 Demand and Energy Data~~. The requirement~~ now states that an entity must report DSM data ~~in parts 1.3.5, and 1.4.5. The requirement also states that an entity must~~and provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 parts 1.5.2, 1.5.3 and 1.5.4).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The standard drafting team accepted this consolidation approach and modified the requirements ~~is intended~~ to ~~maintain NERC's focus on developing and retaining requirements~~ensure data will be made available to ~~that~~ support ~~the~~ assessments of the reliability~~le operation~~ of the Bulk Power System.

~~This white paper provides a record of how the ad hoc group and industry participants in the informal development decided to address the outstanding directives from FERC Order 693, along with the other components of the results-based standards, such as a risk-based and performance-based standard, along with incorporating the Paragraph 81 initiative.~~

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Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R3	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirements R2 and R4	Requirements R2 and R4 of the standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5.
MOD-017-0.1 R1.1	Requirement R1 part 1.3.1	The standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.3.2	The standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.4.1	The standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.4.2	The standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	Omitted	This is no longer need now that all registered entities within each region is a member of that region.
MOD-018-0 R1.2	Requirement R1 part 1.5.1	The standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirements R2 and R4	The standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.4.3	The standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.5.2	The standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.5.3	The standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The standard will require entities to provide the requested data by a certain date.

Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R3~~1~~	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirements R2 and R4	Requirements R2 and R4 of the standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5.
MOD-017-0.1 R1.1	Requirement R1 part 1.3~~4~~.1	The standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.3~~4~~.2	The standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.4~~5~~.1	The standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.4~~5~~.2	The standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	~~Requirement R1 part 1.6~~Omitted	This is no longer need now that all registered entities within each region is a member of that region.
MOD-018-0 R1.2	Requirement R1 part 1.5~~7~~.1	The standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirements R2 and R4	The standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.4~~5~~.3	The standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.5~~7~~.2	The standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.5~~7~~.3	The standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The standard will require entities to provide the requested data by a certain date.

DRAFT Reliability Standard Audit Worksheet[1]

MOD-031-1 – Demand and Energy Data

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						X[3]								
R2	X[4]	X[4]				X[4]								X[4]	
R3	X[5]						X[3,5]								
R4	X					X	X[3]			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.
[4] As identified by a Planning Coordinator or Balancing Authority in a data request issued per Requirement R1 Part 1.1 of MOD-031-1.
[5] As requested by applicable Regional Entity.

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 or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area.[6] The data request shall include:

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator in megawatts for the prior year.

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

[6] For the Balancing Authority, "their area" encompasses their Balancing Authority Area as defined in the NERC Glossary of Terms. For the Planning Coordinator, "their area" encompasses the facilities for which the Planning Coordinator coordinates and integrates transmission facilities, service plans, resource plans, and protection systems.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,[7] temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with 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[8]:

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.
Copies of entity's data requests developed and issued in accordance with Requirement R1, or a statement that no data requests were issued.

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.

[7] For the purpose of this standard, the term "controllable load" means both Interruptible Load and Direct Control Load Management as referenced in FERC Order 693 Paragraph 1267.

[8] 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.

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.
	For data requests selected by auditor for audit testing, review and verify the request included items described in parts 1.1 and 1.2.

Note to Auditor: Items listed in parts 1.3 through 1.5.4 are optional and are included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard.

Entity assertions that no data requests were issued (see "a statement that no data requests were issued" in the Evidence Requested section above) do not have to be in writing.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

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[9]:

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 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 responses to Planning Coordinator or Balancing Authority's data request(s) were made in accordance with Requirement R1 and within timetable established in part 1.2.

Note to Auditor: Based on the language in the requirement and the purpose of the standard, which is to facilitate the sharing of data to support reliability studies, the auditor should not only verify that the data was delivered within the timeframe(s) specified, but also verify that the data delivered met the requirements of the request. However, this standard does not specify criteria around quality of the data, so auditors should not make any assessments in that regard. The responding entity does not have to provide data beyond that requested per parts 1.3 through 1.5.4 of Requirement R1.

[9] 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.

Auditors at their discretion may communicate with Planning Coordinators or Balancing Authorities to determine if data requests made of entity under audit were delivered within the timeframe(s) specified and met the requirements of the request.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity.

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

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[10]:

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 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

[10] 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.

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, 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.
	Review evidence (documented date of the Regional Entity's request and entity's reply) to determine if they provided responses to Regional Entity's data request(s) in accordance with Requirement R3 and within 75 days from the receipt date of the data request.
Note to Auditor: Auditor should communicate with entity's Regional Entity to determine whether the Regional Entity had made a data request to the entity under audit. In the instance where the Planning Coordinator or the Balancing Authority collected additional data from Applicable Entities, the additional information may be provided to the Regional Entity but there is no obligation to do so under this requirement.	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to:

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or

- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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[11]:

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 listed in M4 as well as a copy of the data request; or a statement that a data request was not received.

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.

[11] 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.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, 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.
	Review evidence (documented date of request and reply) to determine if entity responses to data request(s) were made in accordance with Requirement R4 and within 45 days of the date of the written request.

Note to Auditor: Based on the language in the requirement and the purpose of the standard, which is to facilitate the sharing of data to support reliability studies, the auditor should not only verify that the data was delivered within the timeframe(s) specified, but also verify that the data delivered met the requirements of the request. However, this standard does not specify criteria around quality of the data, so auditors should not make any assessments in that regard. The responding entity does not have to provide data beyond that requested per parts 1.3 through 1.5.4 of Requirement R1.

Auditors, at their discretion, may communicate with the requesting Load Serving Entities, Planning Coordinators, Balancing Authorities, Transmission Planners, Resource Planners to determine if responses to data requests were appropriate in accordance with this Requirement.

Entity assertions that no data requests were issued (see "a statement that no data requests were issued" in the Evidence Requested section above) do not have to be in writing.

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/05/2013	NERC compliance, Standards	New Document

Violation Risk Factor and Violation Severity Level Justifications

MOD-031-1 – Demand and Energy Data

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-031-1 – Demand and Energy Data. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, 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 of a medium risk requirement 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, 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.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification – MOD-031-1 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R1 prescribes data that may be collected for analysis. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R1 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to collect data.

VSL Justification – MOD-031-1 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The Requirement is binary and therefore has one VSL.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and therefore has on VSL, severe. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3:	The proposed VSL is consistent with the corresponding requirement.

Violation Severity Level Assignment Should Be 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 proposed VSL is not based on a cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R2 ensures that once data is collected, it is passed on to the appropriate entity. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard:

	All of the parts within Requirement R2 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2:	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2a: The proposed VSL is not binary Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently 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 proposed VSL is not based on cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R3 ensures that once data is collected, it is passed on to the appropriate entity. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R3 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL is worded consistently with the corresponding requirement.

Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R4 ensures that neighboring entities have the ability to collect data. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R4 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the

	standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary

Guideline 2a: The single VSL assignment category for “Binary” Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently 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 proposed VSL is not based on cumulative number of violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Additional Ballot and Non-Binding Poll Now Open through April 10, 2014

Now Available

An additional ballot for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Thursday, April 10, 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.

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
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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Formal Comment Period Now Open through April 10, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: April 1-10, 2014

Now Available

A 45-day formal comment period for **MOD-031-1 – Demand and Energy Data** is open through **8 p.m. Eastern on Thursday, April 10, 2014.**

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 Thursday, April 10, 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 form is posted on the project page.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the 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 at 404-446-2560.

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Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Formal Comment Period Now Open through April 10, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: April 1-10, 2014

Now Available

A 45-day formal comment period for **MOD-031-1 – Demand and Energy Data** is open through **8 p.m. Eastern on Thursday, April 10, 2014.**

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 Thursday, April 10, 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 form is posted on the project page.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the 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.

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Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **MOD-031-1** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Monday, April 14, 2014.**

This standard achieved a quorum and sufficient affirmative votes for approval. 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: 76.92% Approval: 83.40%	Quorum: 76.12% Supportive Opinions: 80.61%

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 standard does not show the need for significant revisions, it will proceed to a final ballot

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2010-04 MOD-031-1 (MOD C) Additional_Ballot _ab_April_2014
Ballot Period:	4/1/2014 - 4/14/2014
Ballot Type:	Successive
Total # Votes:	290
Total Ballot Pool:	377
Quorum:	**76.92 % The Quorum has been reached**
Weighted Segment Vote:	83.40 %
Ballot Results:	**The Ballot has Closed**

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	102	1	58	0.817	13	0.183	0	9	22
2 - Segment 2	9	0.8	7	0.7	1	0.1	0	1	0
3 - Segment 3	85	1	47	0.839	9	0.161	0	7	22
4 - Segment 4	29	1	17	0.739	6	0.261	0	0	6
5 - Segment 5	87	1	38	0.76	12	0.24	0	12	25
6 - Segment 6	50	1	31	0.816	7	0.184	0	5	7
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	0.5	5	0.5	0	0	0	0	3
Totals	**377**	**6.8**	**208**	**5.671**	**48**	**1.129**	**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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
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	Affirmative	
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	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	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
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		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug 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	Affirmative	
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 - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
				SUPPORTS

1	Great River Energy	Gordon Pietsch	Negative	THIRD PARTY COMMENTS - (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		
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	Negative	Supports comments by SPP - Robert Rhodes
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
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	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
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	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	supports the comments of Thomas Foltz - American Electric Power
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
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		
1	PacifiCorp	Ryan Millard		
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		
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	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
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	Abstain	
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	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC Standards Review Committee)
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
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 - (Tom Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
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	Abstain	
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		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

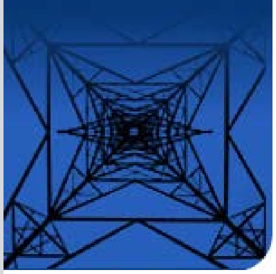
3	Consumers Energy Company	Gerald G Farringer		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	Supports PJMs comments
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Gulf Power Company	Paul C Caldwell		
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
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	Negative	Supports comments by SPP - Robert Rhodes
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		
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	Mississippi Power	Jeff Franklin		
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
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	Affirmative	
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	Affirmative	

3	PacifiCorp	Dan Zollner		
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	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire		
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	Affirmative	
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		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	NO COMMENT RECEIVED - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support the commends of Florida Municipal Power Agency (FMPA))
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
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	Affirmative	
4	Consumers Energy Company	Tracy Goble		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	

4	Oklahoma Municipal Power Authority	Ashley Stringer		
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	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
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	Affirmative	
5	City and County of San Francisco	Daniel Mason		
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	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
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		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
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	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne		
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		
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	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
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	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
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		
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram		
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	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
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	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
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	Affirmative	

5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
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		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
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 - (ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
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	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
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	Affirmative	
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	Affirmative	
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	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	Abstain	
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		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson		
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		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Non-Binding Poll Results

Project 2010-04 Demand Data (MOD C)

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-04 MOD-031-1 (MOD-C)
Poll Period:	4/1/2014 - 4/14/2014
Total # Opinions:	255
Total Ballot Pool:	335
Summary Results:	76.12% of those who registered to participate provided an opinion or an abstention; 80.61% 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	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	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
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		
1	Duke Energy Carolina	Doug 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	Affirmative	
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 - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (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		
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	Negative	Supports comments by SPP - Robert Rhodes
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
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	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan		
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	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		
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		
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	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
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	Abstain	
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	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
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	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		
3	City of Palo Alto	Eric R Scott		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
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		
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	Affirmative	Supports PJMs comments
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
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	Negative	Supports comments by SPP - Robert Rhodes
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		
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	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		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
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	Affirmative	
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	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	Affirmative	
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		
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 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	Affirmative	
4	Consumers Energy Company	Tracy Goble		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
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 - (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	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
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	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Negative	SUPPORTS THIRD PARTY

NERC

				COMMENTS - (ACES)
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	Abstain	
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	Affirmative	
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	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
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		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Energy	Mark Stefaniak		
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne		
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		
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	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	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram		
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	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Santee Cooper	Lewis P Pierce	Abstain	

5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson		
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		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	WPPI Energy	Steven Leovy		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
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 - (ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		

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	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
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	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	Affirmative	
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		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
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	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson		
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		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (33 Responses)
Name (19 Responses)
Organization (19 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (2 Responses)
Comments (33 Responses)
Question 1 (0 Responses)
Question 1 Comments (31 Responses)

Individual
Thomas Neglia
Orange and Rockland Utilities
Agree
Consolidated Edison Company of New York
Group
Northeast Power Coordinating Council
Guy Zito
No comments.
Group
SPP Standards Review Group
Shannon V. Mickens
In the standard: There is a concern surrounding the ‘Applicable Entities’ Which includes ‘Resource Planners’ however; R1 1.1 indicates the request should list the TPs, BAs, LSEs and DPs. We would request clarity to be provided regarding the Resource Planner’s role in reference to R1 1.1. We have a concern that the definition of ‘Total Internal Demand’ in the proposed standard and the (2014) Long Term Reliability Assessment (LTRA) are not consistent. Our request to the drafting team would be to review the definitions in both documents and ensure that we have consistency and efficiency for the applicable standard and assessment process. There is concern surrounding the ‘Applicable Enities’ and their reporting of data in Requirment R4. The requesting and providing of data to the direct Planning Coordinators or Balancing Authoritys will be covered in Requirments R1 and R2. However; the concern would be having ‘Applicable Enities’ to provide this same data numerous time to other Planning Coordinators or Balancing Authoritys who are not in the direct reporting process. We feel that the sharing of the data could be more effiecient if the neighboring Planning Coordinators or Balancing Authoritys would make the data request from

the direct Planning Coordinators or Balancing Authoritys who originally requested the data. R1, VSLs – Revise the Lower VSL to read ‘The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1 late but within 6 days of the date indicated in the timetable provided pursuant to Requirment 1, Part 1.2.’ The Moderate VSL would be revised to read ‘The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1 more than 6 days but within 11 days of the date indicated in the timetable provided pursuant to Requirement R1, Part 1.2.’ The High VSL would be modified in a similar manner substituting 11 days and 15 days for the 6 days and 11 days, respectively, in the Moderate VSL. Typos/grammatical : R1, Part 1.2 and other places within the standard where a specific number of calendar days are specified – 30-calendar days (hyphenate) R1, Parts 1.3.1, 1.3.2, 1.4.1, 1.4.3 – Demand instead of Demands R1, Part 1.5 – Delete ‘about’ at the end. The end of Part 1.5 would then read ‘…summary explanations, as necessary:’ In the Rationale Boxes,in R4 and in the VSLs, capitalize Part when it is associated with part of a Requirement such as Requirement 1, Part 1.3.2. Whitepaper on MOD C Standards: We again suggest that references to the Bulk Power System in the Whitepaper be made to the Bulk Electric System instead. In Footnote 1 at the bottom of Page 5, replace ‘has’ with ‘have’ such that it reads ‘…NERC and the Regional Entities have the authority…’ In the 6th paragraph on Page 5, (2) is akward at best. Perhaps it should read ‘…(2) the sharing of such data among Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners once obtained from a neighboring entity.’ As suggested in the standard, when referenced with a Requirement, Part should be capitalized.
Individual
Chris Scanlon
Exelon
Exelon appreciates the responsiveness of the Drafting Team to comments respecting the role of the LSE's.
Individual
Nazra Gladu
Manitoba Hydro
(1) The new definition of Total Internal Demand should clarify that Total Internal Demand should be reduced by DSM that is not controllable and dispatchable, (i.e., reduced by indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs)) as described in the current Total Internal Demand definition in the NERC Reliability Assessment instructions. Please note that this is only applicable if the intent is to still account for the indirect DSM programs in Total Internal Demand. If this is not the intent, then clarification on the intent of capturing the controllable and dispatchable programs is needed since the definition of DSM has been broadened. (2) R1

– this states that each PC or BA “that identifies a need for the collection of Total Internal Demand ….etc.” On what basis? Or criteria? This could mean that entities are all being treated differently, based upon the “whim” of the PC or BA. There should be defined criteria for when there is a legitimate need. (3) R1 – it is unclear if all data requests should be made in writing. (4) R3 and R4 - for clarity, “days” should be specified as “calendar days”. (5) The standard is vague as to whether or not the load data should be specified as both aggregate and dispersed. From a model building perspective, both are required.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
ATC recommends the SDT consider the following changes to the draft Standard adding clarification to the language of the subrequirements: 1. ATC recommends changing the specified time period in the sub-requirement of R1 from ‘the prior year’ to ‘the prior 12 month period’. This change provides the same function as the original text with added flexibility. 2. ATC recommends to modify Requirement R1.4.3 by adding the word “Annual” at the start of the sub-requirement. a. R1.4.3 would read: “Annual peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.” b. This change would align MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest. 3. ATC recommends to modify Requirements R1.4.5 by adding the word “Annual” at the start of the sub-requirement. a. R1.4.5 would read: “Annual total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” b. This change would align MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest.
Individual
Gul Khan
Oncor Electric Delivery Company LLC
Oncors Commercial Load Management Standard Offer Program (CLMSOP) was developed to pay incentives to energy efficiency service providers (e.g., contractors, energy service companies, retail electric providers, or customers) for load curtailments of electric consumption on short notice during the summer peak period. Incentives are based on verified demand savings that occur at an Oncor distribution customer’s site as a result of a curtailment. Oncor’s CLMSOP is a voluntary program, hence it is not controllable and dispatchable. The program requires service providers to be prepared to participate in up to 25 curtailment hours during the summer peak period. A called curtailment will occur as requested by Oncor. Oncor will comply with ERCOTs requests to deploy the program during or in anticipation of an ERCOT Energy Emergency Alert. Oncor will notify service providers of a called curtailment at least one hour prior to the start-time of the curtailment. Only Oncor authorized personnel can issue notices to service providers to initiate a curtailment. Regarding 1.3.4, Oncor requests the following changes to allow the inclusion of voluntary

Demand Side Management programs: Monthly and annual peak hour controllable and dispatchable, or voluntary Demand Side Management under the control, supervision, or direction of the System Operator or other company representative in megawatts for the prior calendar year. Three values shall be reported for each peak hour curtailment event: 1) the committed megawatts (the amount under control, supervision, or direction), 2) the dispatched or requested megawatts (the amount, if any, activated for use by the System Operator or other company representative), 3) the realized megawatts during curtailment events (the amount of actual demand reduction), 4) type of program (controllable and dispatchable, or voluntary), and 5) System Operator defined monthly and annual peak hours. Regarding 1.4.5, Oncor’s CLMSOP is implemented on a yearly basis and is only projected one year into the future. We recommend the following changes: Total and available peak hour forecast of controllable and dispatchable, or voluntary Demand Side Management (summer and winter), in megawatts, under the control, supervision, or direction of the System Operator or other company representative for their applicable forecasting period. Regarding 1.5.2, Oncor requests the following changes to allow the inclusion of voluntary Demand Side Management programs. We recommend the following changes: The Demand and energy effects of controllable and dispatchable, or voluntary Demand Side Management under the control, supervision, or direction of the System Operator or other company representative. Regarding 1.5.4, Oncor requests the following changes to Reporting Requirement 1.5.2 to allow the inclusion of voluntary Demand Side Management programs : How the controllable and dispatchable, or voluntary Demand Side Management forecast compares to actual controllable and dispatchable, or voluntary Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.
Individual
Michael Falvo
Independent Electricity System Operator
We submitted a couple of comments expressing concerns over the proposed VRFs and VSLs for certain requirements but have not seen a response from the SDT addressing these concerns, nor do we find changes to the draft standard that address these concerns. We’d therefore reiterate our comments as follows: 1. R1: In the sentence “Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data shall develop and issue a data request to the applicable entities in their area.” Suggest to change “their” to “its” before “area”. 2. R1: The wording suggests that the PC and BA shall also distribute the list of applicable entities identified in Part 1.1 as part of the data request. Please clarify whether this is the intent otherwise the requirement will have to be reworded. 3. R1, Part 1.5.5: Suggest to change “peak load” to “Peak Demand” and change “actual load” to “actual Demand”. 4. R4: The SDT’s response to our last comment that the sentence “This requirement does not modify an entity’s obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1.” Was that it provided clarification. While we agree it does serve that purpose, we continue to disagree

with the need to include this statement in Requirement R4. We reiterate our position that the second sentence of R4 is unnecessary and should be deleted and propose the following alternative wording for R4: “Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator or Balancing Authority other than its Planning Coordinator or Balancing Authority, or a Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric Sysytem [sic], provide or otherwise make available that data to the requesting entity. Also, please correct the word “sysytem” to “system”. 5. R4: The first bullet has been modified substantially and now introduces a time limit for provision of the requested data. Since this first bullet now represents a requirement, we believe it appropriate to remove the bullet and make it Part 4.1. We therefore propose that the last part of R4 should read as follows, “Unless otherwise agreed upon, the Applicable Entity shall provide:”, and Part 4.1 should read “The requested data…”. The second bullet of R4 may remain unchanged. 6. R1: Requirement R1 is assigned a MEDIUM VRF. This appears to be inconsistent with the LOW VRF assigned to R1 of MOD-032, which stipulates the requirement for the Planning Coordinator and Transmission Planner to develop the modeling data requirements and reporting procedures. The two requirements appear to be requiring the specification of data and collection procedure required for reliability assessment, yet their VRFs differ by a level. We suggest the SDT to consult the MOD-032 and MOD-033 SDT to confirm the difference based on supporting rationale, or to adjust either VRF to achieve consistency. If the SDT holds the view that the MEDIUM VRF assignment is appropriate, we are unable to find any supporting document that provides the justification for this assignment. If the justification document is posted somewhere and we’ve looked this, please point us to the place where it is posted. 7. There is only one SEVERE VSL for the Planning Coordinator or the Balancing Authority failing to include the entity(s) necessary to provide the data (Part 1.1) or the timetable for providing the data (Part 1.2), but there are no VSLs for the conditions when these entities fail to specify any of Parts 1.3 to 1.5. We suggest to add the VSLs for these conditions to meet the NERC and FERC VSL guidelines. If the SDT holds the view that VSLs for violating Parts 1.3 to 1.5 do not need to be provided, we are unable to find any supporting document that provides the justification for not providing these VSLs. If the justification document is posted somewhere and we’ve looked this, please point us to the place where it is posted.
Individual
Ronda Ferguson
Wisconsin Public Service Corporation
Suggested Language Modification for R1.5.2 (to clarify what is meant by effects): The total demand (Mw) and energy (Mwh) of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator. Suggested Language modification for R1.5.4 and R1.5.5 (clarification of annual): 1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual annual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the

assumptions and methods for future forecasts were adjusted. 1.5.5. How the peak load forecast compares to actual annual peak load for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.
Individual
Bob Steiger
Salt River Project
SRP has no issues with this draft.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
While Seminole generally supports the language contained in the proposed reliability standard, there are still some concerns as outlined below: 1. Requirement R3 states that the PC or BA shall provide certain data within “75 days” of receiving such a request. This requirement does not specify whether the days are “calendar” or “business”. Because the SDT uses “calendar” days in other places throughout the document, the implication is that R3 is meant to refer to business days due to the omission of the word “calendar”. Please revise the proposed language to clearly specify the SDT’s intent. 2. Requirement R4.1 states that Applicable Entities must respond within 30 calendar days of a request. However, if an entity requests data and then the Applicable Entity sends a follow-up request for the reliability need for this data, the Applicable Entity’s response is now contingent upon the timeliness of the response from the requesting entity. This Requirement appears to lack flexibility when a requesting entity does not provide a sufficient reliability need for the data in their initial request. Seminole requests that such flexibility be provided in the Requirement, e.g., 30 calendar days from receipt of a request whose reliability need has been sufficiently communicated.
Individual
Thomas Foltz
American Electric Power
AEP does not support pursuing MOD-031-1. We question the perceived need for this standard, and do not believe it provides any reliability benefit to the BES. Much has changed in the way this information is gathered and reported, and having such a prescriptive standard is not beneficial. To that point, the RTO’s already have established processes which fulfills the need. In addition, this standard dictates how and what type of information is needed for the PC and the BA to do their assessments. It might be preferable that the standard focus on the *what* rather than the *how* and establish a framework for supporting entities to meet the PC and BA’s expectations. We much prefer the approach taken in IRO-010-1a where the standard does not prescribe the details of the data request. Another example is the proposed

standard MOD-032 which addresses similar requirements at a higher level, which we believe is far more appropriate, and preferable, to the highly prescriptive direction taken in MOD-031-1. The comments below are provided in the event the project team continues to pursue the proposed MOD-031-1 standard. R 1.1 – It should be made clear that the list of Functional Entities is provided solely as examples, and is not a requirement that all must be included in the data request. There may be circumstances where RE and Planning Coordinator boundaries do not properly align with the manner in which the requirements are written. The VSL associated with not meeting the expectations of such a data request is Severe. We disagree with the open-endedness of R1, as well as its sole VSL of Severe. AEP recommends changing the proposed definitions to the following: Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to influence the amount or timing of electric usage. Total Internal Demand: The Demand of a metered system which includes the Net Internal Demand, the Demand Response Load and the Load due to the energy losses incurred in the transmission and distribution systems. In addition, we believe the following (new) definitions need to be added to the Definition of Terms section: Demand Response (DR): All programs undertaken by any applicable entity to request that demand be reduced. Examples of DR may include, but are not limited to, Load Management Programs, Direct Control Load Management (DCLM), Interruptible Load or Interruptible Demand, Critical Peak Pricing (CPP) with control, and Load as Capacity resources. Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, less Demand Response (i.e., Direct Control Management and Interruptible Demand). Weather Normalized Demand: A demand that reflects normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 load or demand (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). Additional suggestions (all pages reference the “clean” version of draft document): Pg 6, R1.3.2.1. references weather normalized annual peak without a definition…see definition above for Weather Normalized Demand. Pg 6, R1.3.4 change “controllable and dispatchable Demand Side Management” to “Demand Response” Pg 6, R1.4.5. change “Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” to “Peak hour forecast of available Demand Response (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” Pg 6, R1.5.1 change “aggregate peak’ to “Total Internal” Pages 6 and 7, R1.5 change all references to “controllable and dispatchable Demand Side Management” to “Demand Response”
Group
JEA
Thomas McElhinney
This is purely a data request standard and should be eliminated in accordance with the P81 project.
Individual

Teresa Czyz
Georgia Transmission Corporation
R1 states that the PC and BA “shall develop and issue a data request”, but in R4 includes the TP and RP (in addition to the PC and BA) as giving a “written request for the data”. We are suggesting that the drafting team either add TP and RP to R1 or remove them from R4.
Group
Duke Energy
Michael Lowman
The proposed definition of Demand Side Management appears to be overly broad, and may lead to certain activities or programs to be labeled as Demand Side Management that the SDT did not intend. Duke Energy suggests a re-wording of the proposed definition of Demand Side Management (DSM) to the following: “Demand Side Management: All real-time activities or programs undertaken by any applicable entity to achieve a reduction in Demand.” The addition of the phrase “real-time” adds needed clarity as to the types of activities or programs to be undertaken in the definition, and narrows the scope to avoid unintended inclusions.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst votes in the affirmative for the MOD-031-1 standard but votes in the negative for the non-binding poll. ReliabilityFirst submits the following comment related to the VSL for Requirement R1. 1. The VSL for Requirement R1 only speaks to failing to include either the entity(s) necessary to provide the data (Part 1.2) or the timetable for providing the data (Part 1.2). ReliabilityFirst notes that there is no mention of an entity failing to meet the intent of Part 1.3, Part 1.4 or Part 1.5. Failure to include these Parts in the data request may result in a possible violation and hence need to be noted in the VSLs. ReliabilityFirst recommends including a Moderate VSL such as: “The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include items in Requirement R1, Parts 1.3, Parts 1.4 or Parts 1.4 in the data request.”
Individual
Don Schmit
Nebraska Public Power District
1) The current draft continues to include Requirement R4. As we have stated before, we question the need for this proposed Requirement. While we understand the desire of NERC to encourage the sharing of load data, we continue to believe that a mandatory and enforceable reliability standard is unnecessary and that the sharing of load data would be more effectively addressed by directing requests for such information to the applicable Planning Coordinator

(PC) and not from the entity itself. 2) We are concerned that the draft language under R4 does not provide sufficient protection for applicable entities from differing data requests under Requirements R2 and R4. In the proposed language of Requirement R1, PCs are given a significant amount of flexibility in determining the specific information to be included in their data request to applicable entities. This could create a situation in which an Applicable Entity is required to develop and submit information to comply with a request from another PC under Requirement R4, that they were not required to supply to their direct PC under Requirement R2. At a minimum, NPPD believes a clarification is needed that the information required to be supplied by an Applicable Entity under Requirement R4 be limited to those items it was required to provide to its PC under Requirement R2. 3) The proposed definition of "Total Internal Demand" in the current draft states that it is "The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system." This definition indicates that the controllable and dispatchable DSM load should be added back into the Firm Demand as part of the calculation of Total Internal Demand. The current (2014) Long-Term Reliability Assessment (LTRA) data request also includes the term Total Internal Demand. However, the LTRA instruction for providing Total Internal Demand includes the statement that "Adjustments for controllable demand response should not be included in this value", which doesn't appear to be consistent with the proposed definition in the draft standard. The drafting team needs to ensure that the definitions included in the standard accurately describe the demand and energy information necessary to support reliability studies and assessments and that these definitions are used consistently throughout NERC.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP - Robert Rhodes
Group
DTE Electric
Kathleen Black
We have no issues with the draft of MOD-031-1 standard but wanted to bring to your attention that under M3 (page 9) "Authority" is mispelled.
Group
ISO/RTO Standards Review Committee
Gregory Campoli
The SRC asks for clarification regarding the scope of the proposed standard. Based upon the standards being proposed for retirement (MOD-016,17, 18, 19, and 21) the SRC asks if this standard is designed specifically for the Long Term Planning (LTP) Horizon or is it designed for both Long-term and Operations Planning? The SRC raises the question because: • If the

proposal were only for Long Term Planning, then the SRC would note that in the Functional Model BAs are not involved in LTP, and the BA is therefore not an Applicable Entity. • If the proposal were for both LT Planning and Operations Planning (as implied by having both PC, TP and BA), then it would add clarity to add the Operations Planning Horizon for R1 if both were to need the same listed information; or better to add a standard or a requirement to address the specific data needs of the BA in developing a Day-Ahead operating plan. On the other hand, if the reason for including the BA is to recognize the LTP obligations imposed on the WECC BAs, then the SRC would ask that the SDT explicitly acknowledge that point – e.g. either as a footnote, or in the Applicability section. Please note, CAISO abstained from these comments.
Group
Florida Municipal Power Agency
Frank Gaffney
FMPA has recommended retirement of these standards in accordance with P81, and in alignment with IERP recommendations. The SDT has disagreed, but has not provided sufficient technical justifaction for the existence of a standard. In the SDT's consideration of comments (which by the way does not mention the IERP recommendations to retire these standards), the SDT uses the following reasons to justify a standard: "First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.2 The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment." "Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners to obtain the data from a neighboring entity." These are very weak reasons that do not provide sufficient justification for a standard. First, NERC and RE assessments are not included within the perview of standards. FPA Section 215 section (d) contains the legislation for standards; assessment are included in FPA Section 215 section (g) and are separate from standards in the regulatory construct. Hence, the first "reason" to justify a standard does not provide any justification whatsoever. Second, what are the "reliability purposes" of a PC or BA that would supposedly be facilitated through this effort? There is nothing regarding the BA; there are no Planning Horizon requirements of the BA that involve a planning horizon load forecast, so, there is no reliability purpose of this standard for a BA. The SDT seems to forget that operating horizon load forecasts are already provided in other standards (IRO-010, TOP-002). And the SDT provides no technical justification as to why sharing a planning horizon load forecast with neighbors provides any improvement to reliability. So, to FMPA's reasoning, it really boils down to the TPL standard(s) and whether a planning horizon load forecast is significant enough to the TPL standards to meet the Section 215 thresholds for "reliable operation". That is, from the definitions of Setion 215: "The term

`reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system.” “The term `reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.” A planning horizon load forecast does not provide for “reliable operation” as defined in Section 215. It provides to the TPL standards just a good guess as to what the future load might be in a sampled hour, allocated to individual substations in the model, combined with a generation dispatch that is highly unlikely to occur in real life. The purpose of TPL-001-4 is to: “Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.” In other words, to study reasonable worst case conditions so that we plan a system that can be operated. A planner can establish reasonable worst case conditions without a load forecast provided by someone else using a number of factors such as high load growth cases correlated with hogh economic growth projections for a region, severe weather, etc. Some might say that accuracy of such a forecast is important; but, a forecast is just that, a guess at the future. We cannot know what the weather will be like, we cannot know what the economy is going to do in the future and how that drives load, we cannot know how load growth will vary by sector, we cannot know how load growth will vary from substation to substation, we cannot know the penetration of conservation and DSM programs, etc.. As such, an accurate load forecast is impossible and all we know is that what we forecast will be wrong. This does not mean that it is not important to perform load forecasts for planning purposes, it just does not rise to the signifance of needing to be regulated by standards and instead data requests are sufficient. Hence, the existing standards ought to be retired and replaced with data requests. Also, most PCs are also TSPs, and most TSP OATTs require their network service customers to provide a load forecast; hence, even if the SDT believes, against the IERP recommendations, that there is sufficient technical justification to require a regulatory construct for data collectionof load forecasts, most of those load forecasts are already being collected through the regulatory construct of the OATT. What is not collected through OATTs is certainly inconsequential to BPS reliability In addition, the SDT makes a strange statement in the consideration of comments that says: “(r)eplacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes.” FMPA fails to see how a data request would not provide such a mechanism, and in fact, having a single database for the continent ought to improve such sharing. For instance, in Florida, each utility submits to the FPSC a 10 year site plan with load forecast data that is then made available to other utiltiies in Florida; making the data even more transparent through the FPSC’s collection. It seems to FMPA that the SDT has not given enough consideration to the IERP and other industry expert recommendations to retire these standards. The SDT has not provided sufficient technical justification as to why it disagrees with the Independent Experts except to say that it makes NERC’s and the RE’s life easier and it fulfills an unidentified BA and PC

“reliability purpose”, and a nebulous sharing of data purpose. This seems to FMPA like a “brush off” to important recommendations made by multiple experts in the industry that deserves more careful consideration and deliberation.
Individual
Catherine Wesley
PJM Interconnection
PJM supports the draft standard and appreciates the drafting team implementing PJM’s recommended changes to the definition of Total Internal Demand and R4. Based on the revised draft, PJM will vote in the affirmative. Additionally, PJM suppports the SRC’s comments and has signed onto them.
Group
Dominion
Connie Lowe
1.3.2. Dominion suggests this be re-written similar as 1.3.1; “Integrated monthly and annual peak hour Demands in megawatts for the prior calendar year.” Dominion would like to thank the SDT its response, we still do not agree as the R4 requirement imposes an unnecessary burden on the entity. Given their Planning Coordinator or Balancing Authority already has the information, we suggest that R4 require a requesting Planning Coordinator or Balancing Authority send their data request to the Planning Coordinator or Balancing Authority of the Load-Serving Entity or Distribution Provider.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Controllable and Dispatchable - Currently, Applicable Entities divide demand-side resources generally into two broad groupings: Embedded and Incremental demand-side resources. Embedded demand-side resources are “always on.” Incremental demand-side resources are switched on and off by some mechanism. Embedded demand-side resources are addressed in this standard only indirectly under 1.5.5. Embedded demand-side resources are netted out of both the Forecast and Acutal data. Incremental demand-side resources are not netted out of the Forecast, but are incremental to the base forecast. Howeverver, Incremental demand-side resources can be triggered by many mechanisms. Direct control is only one way to initiate Incremental demand-side resources. Some Incremental demand-side resources are triggered by “rules.” For example, demand-side resources may be initiated whenever some triggering parameters are met, e.g., Load exceeds 96% of Forecast peak, or temperature exceeds 90 degrees prior to 4 critical super peak hours, or by an Economic Demand Response. These demand-side resources are not dispatched in the same strict sense as direct control initiation from a Control Center. Yet they are controllable by predetermined “rules.” Please define the terms controllable and dispatchable. One definition that might be used is: Definition of

Controllable and Dispatchable – Demand-side resource technologies defined by the Planning Coordinator or Planning Authority that are not netted from Forecasts and Actuals. New Technologies – It is not entirely clear how this standard treats evolving, newer technologies. For example, it is not entirely clear how the standard interacts with load shifting technologies, such as cool storage and battery storage; or rechargeable electric vehicles; or Smart Grid? The drafting team should add a further clarifying requirement for the Planning Coordinator or Planning Authority to work with the Applicable Entities to delineate exactly which technologies are to be included and excluded, such as 1.X.X The Planning Coordinator or Planning Authority will work with its Applicable Entities to define in advance the list of technologies which are to be included in the Dispatchabe and Controlable category of demand-side resources and how they are to be modelled. Add the following Standard Definitions: Economic Demand Response (EDR) – EDR is demand-side resources that cause specific changes in the Total Internal Demand in support of system reliability based on their response to specific pricing signals, e.g., 4 hour super-peak pricing. Dispatchable – Demand-side resources that are capable of modifying their Total Internal Demand in response to Applicable Entity instructions.
Group
Western Electricity Coordinating Council
Steve Rueckert
WECC thanks the drafting team for the revisons to several of the definitnions and changes to the requirements that we identified and suggested in the last round of comments. WECC believes this standard is an improvement over the currently-effective standards it is intended to replace and for that reason WECC will be voting YES for this version of the standard. However, as noted in our earlier comments, WECC still has concerns related to the 75-day time frame identified in Requirement R3. Giving the PC or BA up to 75 days to provide the data collected under R2 to the applicable Regional Entity WILL NOT WORK under the schedule currently used at NERC. For example, this year (2014) NERC did not distribute their data request to the Regional Entities until January 7, 2014. Even if the Regional Entities could have requested the data collected under R2 from the PC or BA on the same day and the PC or BA could have turned the request around and sent it to the applicable entitis on the same day, per the language of R1 and R3, it would not be due to the Regional Entity until April 20, 2014 (30 days for applicable entity to respond plus 75 days for the PC or BA to provide the data to the Regional Entity). However, this year the due date for submitting the summer assessment to NERC was March 14. Unless NERC distributes their request to the Regional Entities much earlier, or the Regional entities and the PC or BA agree to a shorter period, the data is not available to the Regional Entity until well after the due date back to NERC. WECC recognizes that a shorter period may be "agreed upon" but because of the language of Requirement R3, the PC or BA could push for 75 days to provide the data. A second concern WECC has voiced in earlier comments is that Requirement R1, part 1.4.3 asks for Peak hour forecast Total Internal Demands (summer and winter) for 10 calendar years. Part 1.4.4 asks for annual Net Energy for 10 years. To do probabilistic studies, monthly peaks and energy are needed. WECC

would like to see the language in parts 1.4.3 and 1.4.4 changed to require monthly peak and monthly energy. WECC has submitted these concerns during earlier comment periods and the drafting team did not address them in their summary response to comments. WECC requests that the drafting team either implement these suggested changes or clearly communicate in the summary response to comments why the suggested changes are not necessary. Without this information WECC will consider voting NO on the next additional ballot or final ballot and suggesting that entities in the West vote NO as well.
Group
ACES Standards Collaborators
Ben Engelby
(1) If the drafting team chooses to modify the NERC Glossary Term for Demand Side Management (DSM), we recommend that a cross reference analysis be peformed with the other reliability standards that use the term DSM. We do not see any type of evaluation of the impact created by the change to the glossary term on these standards. This impact must be evaluated before modifying the definition. (2) We also question the need to add a definition for Total Internal Demand, as the standard should state what data could be requested and would not need a definition for this purpose. According to the NERC Drafting Team Guidelines, dated April 2009, the guidance states that an SDT “should avoid developing new definitions unless absolutely necessary.” There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the phrase rather than trying to obtain stakeholder consensus on the new term. Further, the proposed definition conflicts directly with the term as used in the NERC Long-Term Reliability Assessments and Seasonal Assessments. In these assessments Total Internal Demand is the demand without reducing for DSM. Net Internal Demand is the term used for the demand after removing DSM from the demand. We recommend removing the term for Total Internal Demand from the standard. (3) We do not understand how the modified purpose statement in the standard supports reliability because it is redundant with authority already granted NERC through its Rules of Procedure. The rationale provided by the SDT is to clearly state the intention of the standard, but we believe that the collection of Demand and energy data is administrative in nature and would qualify for Paragraph 81 retirement. This data is better suited for a section 1600 data request, which NERC and the Regional Entities already have authority to initiate. We believe the team needs to reevaluate this purpose of this standard, remove administrative tasks from the requirements, and focus on the activities needed for a more reliable system. We also believe the drafting team should ultimately retire all similar requirements and move them to

a section 1600 data request. As reflected in Paragraph 81 criteria, data collection is not well suited for compliance monitoring. A section 1600 data request is mandatory and this would provide the appropriate incentive to ensure data is submitted without stifling the interaction between the data submitter and the receiver on whether the data is satisfactory. When data submittal is required by standards, data receivers are often reluctanct to comment on the satisfactory nature of the data for fear of being becoming involved in another party's compliance monitoring. This could result in data submitted that does not meet the receiver's needs. There is no need to develop a standard for a data request because the NERC Rules of Procedure already provide equally effective alternate measures to obtain the data. (4) We disagree with several aspects to Requirement R1 because they meet P81 criteria. Further, the RSAW states that items listed in parts 1.3 through 1.5.4 are optional and are included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard. These aspects of R1 meet Paragraph 81 criteria and need to be revised. According to P81, requirements for data requests are an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES (criterion A). In addition to criterion A, these data requests are administrative in nature (criterion B1), focus on data collection/data retention (criterion B2), require entities to develop a document that is not necessary to protect BES reliability (criterion B3), require reporting to another entity or party (criterion B4), and require responsible entities to periodically update documentation without an operational benefit to reliability (criterion B5). Based on these reasons, we ask the drafting team to revise the requirement so only activities directly relating to reliability are addressed. (5) Distribution Provider should be removed from Part 1.1. All of the DP's load will already be reported via the LSE or BA. NERC compliance registry criterion III.a.4 is very clear that DPs "will be registered as a Load Serving Entity (LSE) for all load directly connected to their distribution facilities." Thus, applicability to DP is not needed. (6) For Requirement R2, we agree that the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard. However, we continue to believe that R2 also meets P81 criteria because the language in the requirement and the purpose of the standard is to facilitate the sharing of data. (7) For Requirement R3, there should not be a standard for complying with a Regional Entity. The NERC Rules of Procedure outline several methods including a section 1600 data request for regional entities and NERC to request data and may impose sanctions to those entities that fail to comply. There is an equally efficient alternative to achieve the same result that is being sought in R3. We recommend striking the requirement. (8) For Requirement R4, we do not see the need for this requirement and the timelines are arbitrary. As stated above, the items in this requirement meet P81 criteria. For instance, listing the data that could be requested, the neighboring entities that could request data and the conditions for when a data provider could refuse to provide the data are all administrative tasks that do not benefit or protect the reliable operation of the BES. We recommend striking this requirement. (9) In regard to the VSLs/VRFs, since we disagree with the approach of the drafting team's modified requirements, we also disagree with the corresponding VSLs and VRFs. (10) Thank you for the opportunity to comment.

Group
Florida Power & Light
Mike O'Neil
It is currently unclear if the different reporting requirements will result in FPL no longer being able to point to its Ten Year Site Plan filing with the FPSC as the place where all of the data currently requested in MODs 16-19 and 21 are found. One example is the apparent change in load forecasting regarding weather-normalized load.
Group
Tennessee Valley Authority
Dennis Chastain
TVA appreciates the efforts of the Standards Drafting Team to develop this replacement standard and address FERC's directives. As stated in our comments on the second draft, it is unclear if the purpose of the replacement standard is to facilitate demand and energy data collection by the registered entities who have a reliabiliy related need to obtain the data for the purpose of making BES infrastructure decisions (the TP/TO and RP/GO), or if the end purpose is to provide data to the Regional Entity / ERO for the purpose of producing regional or NERC wide reliability assessments. With the latest draft, it seems more evident that the drafting team is working toward the latter. That being the case, we believe a "paragraph 81" review leading to the retirement of these standards is the more appropriate course. Furthermore, the proposed standard would only address the demand and energy data aspect of the regional and NERC level assessment needs, with no corresponding standard/requirements for the collection of resource data. If the standard moves forward as currently drafted, can a PC or BA elect not to request any (or some) data under R1 and when requested by the Regional Entity to provide the data (R2) respond that it has not collected it? A proposed solution is for the drafting team to revise the purpose of the standard to be - "To enable Transmission Planners and Resource Planners to define and collect the Demand, energy and related data necessary to perform planning studies that support future intrastructure build decisions by the Transmission Owner and Generation Owner." If the drafting team moves forward with this focus, the requirements will need further work. The standard's applicability could be revised to include a "Demand/Energy Data Entity" (reference PRC-006-1 for similar precedent - "UFLS Entity") that can include the LSE, DP, BA or TO. We believe a standard developed under this purpose, while still seeking to address FERC's directives, would be of more reliability benefit than a standard that focuses on partial data collection needed for Regional Entity / ERO assessments.
Group
Bonneville Power Administration
Andrea Jessup

BPA would like to see a change to MOD-031-1 which was previously considered during comment periods. Requirement 1.3.2.1 requires that each Applicable Entity perform a weather normalization calculation on the peak hour data. Weather normalization calculations are extremely complicated and have a wide distribution of methods applied with inconsistent results. The most effective planning can be achieved if the entity using the data applies a consistent method to the data. Therefore we think this requirement should ask for the date/time of the peak occurrence. With that data the planning entity can perform their own analysis with the weather variables they feel are applicable. Other than this comment BPA supports the changes and is in agreement with the proposal. Previously MOD-031-1 had changed the wording to include “may” weather normalize the data. Alternatively to asking for the data/time of the peak occurrence replacing the word “shall” with “may” in the text of this requirement would also allow the Applicable Entity to determine if they have sufficient means to do the weather normalization and not provide data if they are not skilled at calculating the quantity. The proposed MOD-031-1 standard appears to remove the existing MOD-016-1.1 R1.1 requirement that requires consistent data submittals are supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. As these TPL and remaining MOD standards still have a dependency on similar data requests/submittals, BPA feels this standard has inappropriately dropped language that requires consistency between the MOD and TPL standards.
Group
Cooper Compliance Corp
Mary Jo Cooper
Particular to Standard MOD-031, the drafting team should consider requiring BAs and PCs to post the data request on their website and distribute the request to other entities one (1) year in addition to sending a reminder (1) quarter year (3 months) prior to the due dates. Thirty (30) day data requests are time consuming and often these requests are made to the incorrect person. Furthermore, the detail for what should be received in the request should be stated by the BA or PC and not by the Standard.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Please consider using IRO-010-1a R1 as a guideline for allowing an reliability entity to ask for what is required without being so prescriptive and yet limiting to the requestor. This standard is very similar in nature to IRO-010-1a and should be consistent with such a format. M1, M2, M3: Propose deleting prescriptive elements in measures. If the data request needs to be dated or the format has to be a certain way, then it should be in the requirement and not in the measure. Preferable means of evidence can be listed in the RSAW but are not requirements. Recommend for most instances to include “or other equivalent evidence” to allow flexibility for a responsible entity and the auditor to accept such means of evidence. R4:

Delete “with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System”. This statement is ambiguous and leaves language open to interpretation. Recommend just including TP and RP in R1 and delete R4 to simplify. There should not be a distinction between how or what you provide to a reliability entity that has reliability tasks to perform. If you simplify R1 to be consistent with IRO-010-1a, this makes the standard much simpler and streamlined. R4.1: Applicable entities should be required to provide data without exception and therefore propose removing language that would allow entities to explain why they will not provide requested data. M4: Removed language related to R4.1 that would allow for explanation for non-submittals Table of Compliance Elements: Recommend modifying the VRFs and VSLs to that which is consistent with IRO-010-1a. Issuing a request for data is not a medium VRF, nor providing to the RE when applying the violation risk factor guideline. Similar to IRO-010-1a, it is possible to allow for so different variations to graduate the VSLs in severity consistent with the VSL guideline document. General comment is that with the modifications to the definition to DSM and the introduction of Total Internal Demand, NERC and or the SDT should review the potential impact or necessity for modifications to other existing NERC Reliability standards which use those terms or terms that are included in the make up identified in the definition. An example would be the use of interruptible load vs DSM in other standards. Also, it is unclear if there are controls that limit the double counting of load under Firm Demand and or controllable and dispatchable DSM load as load by definition is Firm until a certain criteria is reached allowing the use of the DSM load.
Individual
Spencer Tacke
Modesto Irrigation District
I want to vote NO on MOD-031-1. The reason is because of the language in Section B R1 1.3.2. I don’t believe we should be skewing the actual demand data recorded, that is then subsequently used in our analysis work.
Individual
Mahmood Safi
Omaha Public Power District
OPPD recommends that the SDT consider revising DSM description used in Requirement R1 Part 1.3.4 to be consistence with the description of DSM used in the NERC Long-Term Reliability Assessment (LTRA).

Consideration of Comments

Project 2010-04 Demand Data (MOD C)

The Project 2010-04 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from February 25, 2014 through April 10, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 33 sets of comments, including comments from approximately 119 different people from approximately 73 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

1. Please provide any issues you have on this draft of the MOD-031-1 standard and a proposed solution.. 10

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 - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

Registered Ballot Body Segment: columns 1–10.

10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michelle Corley	Cleco Power, LLC	SPP	1, 3, 5, 6
2.	Mike Kidwell	Empire District Electric Company	SPP	1, 3, 5
3.	Katy Onnen	Kansas City Power & light Company	SPP	1, 3, 5, 6
4.	Tim Owens	Nebraska Public Power District	SPP	1, 3, 5
5.	Valerie Pinamonti	American Eletric Power	SPP	1, 3, 4, 5
6.	Stephanie Johnson	Westar	SPP	1, 3, 5, 6
7.	Lisa Stites	Westar	SPP	1, 3, 5, 6
8.	Derek Brown	Westar	SPP	1, 3, 5, 6
9.	Bo Jones	Westar	SPP	1, 3, 5, 6
10.	Robin Spady	Municipal Energy Agency of Nebraska	SPP	5
11.	Robert Rhodes	SPP	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Thomas McElhinney	JEA	X		X		X					

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
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils			1
2.	Lee Schuster			3
3.	DaleGoodwinw			5
4.	Greg Cecil			6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	NPCC	4
3.	Mark Stefaniak	Regulated Marketing	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Gregory Campoli	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matthew Goldberg	ISONE	NPCC	2
2.	Ben Li	IESO	NPCC	2
3.	Stephanie Monzon	PJM	RFC	2
4.	Cheryl Moseley	ERCOT	ERCOT	2
5.	Ed Skiba	MISO	RFC	2
6.	Charles Yeung	SPP	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

6. Randy Hahn	Ocala Utility Services	FRCC	3
7. Stanley Rzad	Keys Energy Services	FRCC	1
8. Don Cuevas	Beaches Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton	NERC Compliance Policy	NPCC	5, 6
2. Randi Heise	NERC Compliance Policy	MRO	6
3. Louis Slade	NERC Compliance Policy	RFC	5, 6
4. Larry Nash	Electric Transmission Compliance	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

Additional Member	Additional Organization	Region	Segment Selection
1. Layne Brown	WECC	WECC	10

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
2.	Kevin Lyons	Central Iowa Power Cooperative	MRO	
3.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
4.	Chip Koloni	Golden Spread Electric Cooperative, Inc.	SPP	5
5.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
6.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
7.	Ginger Mercier	Prairie Power, Inc.	SERC	3
8.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
9.	Joel Rogers	South Mississippi Electric Power Association	SERC	1, 3, 4, 5, 6
10.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Mike O'Neil	Florida Power & Light	X									

No Additional Responses

Group/Individual		Commenter	Organization	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. DeWayne Scott		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
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Reed Davis	Load Forecasting & Analysis	WECC	1
2.	Lindsay Wickizer	FERC Compliance	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Mary Jo Cooper	Cooper Compliance Corp	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Douglas Draeger	Alameda Municial Power	WECC	3
2.	Dennis Schmidt	Anaheim Water and Power	WECC	3
3.	Mel Grandi	City of Ukiah	WECC	3
4.	Angela Kimmey	Pasadena Water and Power	WECC	1, 3
5.	Ken Dize	Salmon River Electric Coop	WECC	1, 3
6.	Fred Fletcher	Burbank Water and Power	WECC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Individual	Thomas Neglia	Orange and Rockland Utilities	X		X							
16.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
17.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
18.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
19.	Individual	Gul Khan	Oncor Electric Delivery Company LLC	X									
20.	Individual	Michael Falvo	Independent Electricity System Operator		X								
21.	Individual	Ronda Ferguson	Wisconsin Public Service Corporation			X	X	X	X				
22.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
23.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
24.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
25.	Individual	Teresa Czyz	Georgia Transmission Corporation	X									
26.	Individual	Anthony Jablonski	ReliabilityFirst										X
27.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
29.	Individual	Catherine Wesley	PJM Interconnection		X								
30.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
31.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
32.	Individual	Spencer Tacke	Modesto Irrigation District				X						
33.	Individual	Mahmood Safi	Omaha Public Power District	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:

Organization	Agree	Supporting Comments of "Entity Name"
Orange and Rockland Utilities	Agree	Consolidated Edison Company of New York
Kansas City Power & Light	Agree	SPP - Robert Rhodes

1. Please provide any issues you have on this draft of the MOD-031-1 standard and a proposed solution

Summary Consideration:

Organization	Question 1 Comment
Manitoba Hydro	(1) The new definition of Total Internal Demand should clarify that Total Internal Demand should be reduced by DSM that is not controllable and dispatchable, (i.e., reduced by indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs)) as described in the current Total Internal Demand definition in the NERC Reliability Assessment instructions. Please note that this is only applicable if the intent is to still account for the indirect DSM programs in Total Internal Demand. If this is not the intent, then clarification on the intent of capturing the controllable and dispatchable programs is needed since the definition of DSM has been broadened. (2) R1 - this states that each PC or BA “that identifies a need for the collection of Total Internal Demand ....etc.” On what basis? Or criteria? This could mean that entities are all being treated differently, based upon the “whim” of the PC or BA. There should be defined criteria for when there is a legitimate need. (3) R1 - it is unclear if all data requests should be made in writing. (4) R3 and R4 - for clarity, “days” should be specified as “calendar days”. (5) The standard is vague as to whether or not the load data should be specified as both aggregate and dispersed. From a model building perspective, both are required.

Organization	Question 1 Comment
Response: (1) Metered system and firm Demand already includes the impacts of DSM that is not controllable and dispatchable (indirect DSM). **(2) The intent was, because some PC's or BA's may not need to collect this data through this standard, for this statement to give them the ability to not issue a data request under this standard. Furthermore, this standard limits the scope of data requirements for those PC's and BA's that need to use this standard to collect the data.** **(3) The standard drafting team (SDT) believes that the phrase "issue a data request" indicates that this will be in writing. In addition, the measure states that compliance will be demonstrated by having a "dated data request, either in hardcopy or electronic format".** **(4) Thank you and the SDT added the word "calendar".** **(5) MOD-016 referenced a list of standards that address reporting of data on an aggregate and dispersed basis. The standards from that list incorporated into MOD-031 only address aggregate data. Other standards from that list that have been incorporated into MOD-032 address reporting of dispersed Demand information.**	
ACES Standards Collaborators	(1) If the drafting team chooses to modify the NERC Glossary Term for Demand Side Management (DSM), we recommend that a cross reference analysis be peformed with the other reliability standards that use the term DSM. We do not see any type of evaluation of the impact created by the change to the glossary term on these standards. This impact must be evaluated before modifying the definition. (2) We also question the need to add a definition for Total Internal Demand, as the standard should state what data could be requested and would not need a definition for this purpose. According to the NERC Drafting Team Guidelines, dated April 2009, the guidance states that an SDT "should avoid developing new definitions unless absolutely necessary." There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or

Organization	Question 1 Comment
	a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the phrase rather than trying to obtain stakeholder consensus on the new term. Further, the proposed definition conflicts directly with the term as used in the NERC Long-Term Reliability Assessments and Seasonal Assessments. In these assessments Total Internal Demand is the demand without reducing for DSM. Net Internal Demand is the term used for the demand after removing DSM from the demand. We recommend removing the term for Total Internal Demand from the standard. (3) We do not understand how the modified purpose statement in the standard supports reliability because it is redundant with authority already granted NERC through its Rules of Procedure. The rationale provided by the SDT is to clearly state the intention of the standard, but we believe that the collection of Demand and energy data is administrative in nature and would qualify for Paragraph 81 retirement. This data is better suited for a section 1600 data request, which NERC and the Regional Entities already have authority to initiate. We believe the team needs to reevaluate this purpose of this standard, remove administrative tasks from the requirements, and focus on the activities needed for a more reliable system. We also believe the drafting team should ultimately retire all similar requirements and move them to a section 1600 data request. As reflected in Paragraph 81 criteria, data collection is not well suited for compliance monitoring. A section 1600 data request is mandatory and this would provide the appropriate incentive to ensure data is submitted without stifling the interaction between the data submitter and the receiver on whether the data is satisfactory. When data submittal is required by standards, data receivers are often reluctant to comment on the satisfactory nature of the data for fear of being becoming involved in another party's compliance monitoring. This could result in data submitted that does not meet the receiver's needs. There is no need to develop a standard for a data request because the NERC Rules of Procedure already provide equally effective alternate measures to obtain the data. (4) We disagree with several aspects to Requirement R1 because they meet P81 criteria. Further, the RSAW states that items listed in parts 1.3 through 1.5.4 are optional and are

Organization	Question 1 Comment
	included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard. These aspects of R1 meet Paragraph 81 criteria and need to be revised. According to P81, requirements for data requests are an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES (criterion A). In addition to criterion A, these data requests are administrative in nature (criterion B1), focus on data collection/data retention (criterion B2), require entities to develop a document that is not necessary to protect BES reliability (criterion B3), require reporting to another entity or party (criterion B4), and require responsible entities to periodically update documentation without an operational benefit to reliability (criterion B5). Based on these reasons, we ask the drafting team to revise the requirement so only activities directly relating to reliability are addressed. (5) Distribution Provider should be removed from Part 1.1. All of the DP's load will already be reported via the LSE or BA. NERC compliance registry criterion III.a.4 is very clear that DPs "will be registered as a Load Serving Entity (LSE) for all load directly connected to their distribution facilities." Thus, applicability to DP is not needed. (6) For Requirement R2, we agree that the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard. However, we continue to believe that R2 also meets P81 criteria because the language in the requirement and the purpose of the standard is to facilitate the sharing of data. (7) For Requirement R3, there should not be a standard for complying with a Regional Entity. The NERC Rules of Procedure outline several methods including a section 1600 data request for regional entities and NERC to request data and may impose sanctions to those entities that fail to comply. There is an equally efficient alternative to achieve the same result that is being sought in R3. We recommend striking the requirement. (8) For Requirement R4, we do not see the need for this requirement and the timelines are arbitrary. As stated above, the items in this requirement meet P81 criteria. For instance, listing the data that could be requested, the neighboring entities that could

Organization	Question 1 Comment
	request data and the conditions for when a data provider could refuse to provide the data are all administrative tasks that do not benefit or protect the reliable operation of the BES. We recommend striking this requirement. (9) In regard to the VSLs/VRFs, since we disagree with the approach of the drafting team's modified requirements, we also disagree with the corresponding VSLs and VRFs. (10) Thank you for the opportunity to comment.

Response: (1) The list of standards that use the term "Demand Side Management" is contained in the Implementation Plan that was posted with the draft standard. The SDT reviewed the standards and did not find any instances where the suggested modification caused any substantive or material changes to the intent of those standards.

(2) Metered system and firm Demand already includes the impacts of DSM that is not controllable and dispatchable (indirect DSM). The definition of Total Internal Demand explicitly states that the effects of controllable and dispatchable DSM is not included.

(3) The purpose statement states that the standards' purpose is to provide the authority for an applicable entity to collect the data necessary for reliability assessments. NERC is not listed as an applicable entity. The standard is targeted towards a PC or BA.

(4) The intent was, because some PC's or BA's may not need to collect this data through this standard, for this statement to give them the ability to not issue a data request under this standard. Furthermore, this standard limits the scope of data requirements for those PC's and BA's that need to use this standard to collect the data.

(5) The SDT believes that Demand forecast may require input from the DP, therefore, the PC's and BA's need to have the ability to request the data from the DP.

(6) The purpose of this standard and its requirements is to ensure that all PC's and BA's have the authority to collect the applicable data. The intent of the requirements are to limit the scope of the data that may be requested under this standard and ensure that the applicable data owners comply with the request.

(7) The SDT believes that Requirement R3 is necessary to clearly state that the PC or BA have an obligation to provide data collected to the Regional Entity when the Regional Entity requested the data. The SDT also added a minimum time frame for responding to a data request from the Regional Entity. This was to ensure that the PC or BA would have sufficient time to gather the data and provide it to the Regional Entity.

Organization	Question 1 Comment
(8) The SDT is providing an equally effective and efficient method for responding to a FERC directive, which required the collection of temperature and humidity. The SDT believes that requiring hourly temperature and humidity values would provide no value since there are differing methods used to weather normalize Demand. The method an entity would use to weather normalize their actual data should be dependent on their unique system configuration.	
hNebraska Public Power District	1) The current draft continues to include Requirement R4. As we have stated before, we question the need for this proposed Requirement. While we understand the desire of NERC to encourage the sharing of load data, we continue to believe that a mandatory and enforceable reliability standard is unnecessary and that the sharing of load data would be more effectively addressed by directing requests for such information to the applicable Planning Coordinator (PC) and not from the entity itself. 2) We are concerned that the draft language under R4 does not provide sufficient protection for applicable entities from differing data requests under Requirements R2 and R4. In the proposed language of Requirement R1, PCs are given a significant amount of flexibility in determining the specific information to be included in their data request to applicable entities. This could create a situation in which an Applicable Entity is required to develop and submit information to comply with a request from another PC under Requirement R4, that they were not required to supply to their direct PC under Requirement R2. At a minimum, NPPD believes a clarification is needed that the information required to be supplied by an Applicable Entity under Requirement R4 be limited to those items it was required to provide to its PC under Requirement R2. 3) The proposed definition of “Total Internal Demand” in the current draft states that it is “The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.” This definition indicates that the controllable and dispatchable DSM load should be added back into the Firm Demand as part of the calculation of Total Internal Demand. The current (2014) Long-Term Reliability Assessment (LTRA) data request also includes the term Total Internal Demand. However, the LTRA instruction for providing Total Internal Demand includes the statement that “Adjustments for controllable demand response should not be included in this value”,

Organization	Question 1 Comment
	which doesn't appear to be consistent with the proposed definition in the draft standard. The drafting team needs to ensure that the definitions included in the standard accurately describe the demand and energy information necessary to support reliability studies and assessments and that these definitions are used consistently throughout NERC.
Response: (1) The SDT is providing an equally effective and efficient method for responding to a FERC directive, which required the collection of temperature and humidity. The SDT believes that requiring hourly temperature and humidity values would provide no value since there are differing methods used to weather normalize Demand. The method an entity would use to weather normalize their actual data should be dependent on their unique system configuration. **(2) You are correct in that different requests could be for different data. The backstop is the limit on the data that can be requested as defined in Requirement R1.** **(3) Metered system and firm Demand already includes the impacts of DSM that is not controllable and dispatchable (indirect DSM). The definition of Total Internal Demand explicitly states that the effects of controllable and dispatchable DSM is not included.**	
Dominion	1.3.2. Dominion suggests this be re-written similar as 1.3.1; "Integrated monthly and annual peak hour Demands in megawatts for the prior calendar year." 1.3.3. Dominion would like to thank the SDT its response, we still do not agree as the R4 requirement imposes an unnecessary burden on the entity. Given their Planning Coordinator or Balancing Authority already has the information, we suggest that R4 require a requesting Planning Coordinator or Balancing Authority send their data request to the Planning Coordinator or Balancing Authority of the Load-Serving Entity or Distribution Provider.
Response: The term "integrated" is referencing what is done to the "peak hour" Demand and therefore should remain close to the term hour. The SDT believes that the current wording implies that the "peak hour" is integrated but your suggestion could imply that the integration would take place over the month or year. **The SDT is providing an equally effective and efficient method for responding to a FERC directive, which required the collection of temperature and humidity. The SDT believes that requiring hourly temperature and humidity values would provide no value since**	

Organization	Question 1 Comment
there are differing methods used to weather normalize Demand. The method an entity would use to weather normalize their actual data should be dependent on their unique system configuration.	
American Electric Power	AEP does not support pursuing MOD-031-1. We question the perceived need for this standard, and do not believe it provides any reliability benefit to the BES. Much has changed in the way this information is gathered and reported, and having such a prescriptive standard is not beneficial. To that point, the RTO's already have established processes which fulfills the need. In addition, this standard dictates how and what type of information is needed for the PC and the BA to do their assessments. It might be preferable that the standard focus on the *what* rather than the *how* and establish a framework for supporting entities to meet the PC and BA's expectations. We much prefer the approach taken in IRO-010-1a where the standard does not prescribe the details of the data request. Another example is the proposed standard MOD-032 which addresses similar requirements at a higher level, which we believe is far more appropriate, and preferable, to the highly prescriptive direction taken in MOD-031-1.The comments below are provided in the event the project team continues to pursue the proposed MOD-031-1 standard. R 1.1 - It should be made clear that the list of Functional Entities is provided solely as examples, and is not a requirement that all must be included in the data request. There may be circumstances where RE and Planning Coordinator boundaries do not properly align with the manner in which the requirements are written. The VSL associated with not meeting the expectations of such a data request is Severe. We disagree with the open-endedness of R1, as well as its sole VSL of Severe. AEP recommends changing the proposed definitions to the following: Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to influence the amount or timing of electric usage.

Organization	Question 1 Comment
	Total Internal Demand: The Demand of a metered system which includes the Net Internal Demand, the Demand Response Load and the Load due to the energy losses incurred in the transmission and distribution systems. In addition, we believe the following (new) definitions need to be added to the Definitionof Terms section: Demand Response (DR): All programs undertaken by any applicable entity to request that demand be reduced. Examples of DR may include, but are not limited to, Load Management Programs, Direct Control Load Management (DCLM), Interruptible Load or Interruptible Demand, Critical Peak Pricing (CPP) with control, and Load as Capacity resources. Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, less Demand Response (i.e., Direct Control Management and Interruptible Demand). Weather Normalized Demand: A demand that reflects normal weather conditions, and is expected on a 50% probability basis - also known as a 50/50 load or demand (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). Additional suggestions (all pages reference the “clean” version of draft document): Pg 6, R1.3.2.1. references weather normalized annual peak without a definition...see definition above for Weather Normalized Demand. Pg 6, R1.3.4 change “controllable and dispatchable Demand Side Management” to “Demand Response” Pg 6, R1.4.5. change “Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” to “Peak hour forecast of available Demand Response (summer and winter), in megawatts,

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	under the control or supervision of the System Operator for ten calendar years into the future." Pg 6, R1.5.1 change "aggregate peak' to "Total Internal" Pages 6 and 7, R1.5 change all references to "controllable and dispatchable Demand Side Management" to "Demand Response"

Response: R1.1 – The SDT concludes that Requirement R1, part 1.1 is sufficiently clear. The list of functional entities in part 1.1 represents those functional entities that may be required to provide data upon request. A PC or a BA, as applicable, is not required to list all of those functional entities in its data request. A PC or BA need only identify in its data request those functional entities that have the necessary Demand and energy data.

With regards to alignment across PC boundaries, the entities are expected to report the data associated with the applicable PC. These issues currently exist and have already been resolved.

Concerning your comment about the VSL for Requirement R1, the SDT does not believe that the requirement is open ended rather the SDT feels that using the phrase "any or all" in parts 1.3, 1.4 and 1.5 provides flexibility to allow for instances when a requestor may not have a reliability need to collect all of the data outlined within the standard. Using this approach, the SDT does not believe that it can write a VSL for parts 1.3, 1.4 and 1.5. Since the inclusion of some or all of the data listed in these parts is optional, then it would not make sense to have VSL's requiring some or all of the data. Removing parts 1.3, 1.4 and 1.5 from the VSL leaves only parts 1.1 and 1.2. If either of these two parts are left out of a data request then either the data owners or the timeline for responding would be missing and thus make the data request invalid. This turns the requirement into a binary (yes or no) type of requirement which according to the VSL guidelines carries only a severe level.

With regards to your suggested wording for Demand Side Management, the SDT believes that the term "influence" does not adequately describe what the SDT intends and is not measureable.

The SDT does not believe that it is necessary to add another definition to the Glossary of Terms (Demand Response). The current suggested definitions are adequate to cover the concepts in this standard. Also, your suggested definition would double count non-controllable DR programs.

The SDT believes that the term "weather normalized" is descriptive enough.

Pg 6, R1.3.2.1 – As stated above, the SDT believes that the term "weather normalized" is descriptive enough.

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Pg 6, R1.3.4 & Pg 6, R1.4.5 – The SDT believes that "controllable and dispatchable" are descriptive enough. Also, please see our response to your suggested addition of the term "Demand Response". **Pg 6, R1.5.1 – The SDT is using the current definition for Demand since we are only looking for their methodology in developing forecasts.** **Pages 6 and 7, R1.5 – Please see our response to your comment for Pg 6 R1.3.4**	
American Transmission Company, LLC	ATC recommends the SDT consider the following changes to the draft Standard adding clarification to the language of the subrequirements: 1. ATC recommends changing the specified time period in the sub-requirement of R1 from 'the prior year' to 'the prior 12 month period'. This change provides the same function as the original text with added flexibility. 2. ATC recommends to modify Requirement R1.4.3 by adding the word "Annual" at the start of the sub-requirement. a. R1.4.3 would read: "Annual peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future." b. This change would align MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest. 3. ATC recommends to modify Requirements R1.4.5 by adding the word "Annual" at the start of the sub-requirement. a. R1.4.5 would read: "Annual total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future." b. This change would align MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest.

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Response: (1) The SDT believes that the current language provides a better description for the period the standard is trying to capture. Depending upon when the request would be sent, an entire year may not be captured. (2) & (3) The SDT believes that adding the word "annual" does not provide any additional clarity and could cause confusion because the term has been found to be ambiguous for other standards and because of the non-annual nature of the winter season straddling calendar years.	
Bonneville Power Administration	1) BPA would like to see a change to MOD-031-1 which was previously considered during comment periods. Requirement 1.3.2.1 requires that each Applicable Entity perform a weather normalization calculation on the peak hour data. Weather normalization calculations are extremely complicated and have a wide distribution of methods applied with inconsistent results. The most effective planning can be achieved if the entity using the data applies a consistent method to the data. Therefore we think this requirement should ask for the date/time of the peak occurrence. With that data the planning entity can perform their own analysis with the weather variables they feel are applicable. Other than this comment BPA supports the changes and is in agreement with the proposal. Previously MOD-031-1 had changed the wording to include "may" weather normalize the data. Alternatively to asking for the data/time of the peak occurrence replacing the word "shall" with "may" in the text of this requirement would also allow the Applicable Entity to determine if they have sufficient means to do the weather normalization and not provide data if they are not skilled at calculating the quantity. 2) The proposed MOD-031-1 standard appears to remove the existing MOD-016-1.1 R1.1 requirement that requires consistent data submittals are supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. As these TPL and remaining MOD standards still have a dependency on similar data requests/submittals, BPA feels this standard has inappropriately dropped language that requires consistency between the MOD and TPL standards.

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Response: 1) The SDT is providing an equally effective and efficient method for responding to a FERC directive, which required the collection of temperature and humidity. The SDT believes that requiring hourly temperature and humidity values would provide no value since there are differing methods used to weather normalize Demand. The method an entity would use to weather normalize their actual data should be dependent on their unique system configuration. The SDT ascertains that the entity that performs the forecasting would be in the best position to perform the weather normalization. **2) The SDT believes that the consistency is accomplished at the data owner level through coordination between TO's and LSE's pursuant to MOD-032.**	
Consolidated Edison Co. of NY, Inc.	1) Controllable and Dispatchable - Currently, Applicable Entities divide demand-side resources generally into two broad groupings: Embedded and Incremental demand-side resources. Embedded demand-side resources are "always on." Incremental demand-side resources are switched on and off by some mechanism. Embedded demand-side resources are addressed in this standard only indirectly under 1.5.5. Embedded demand-side resources are netted out of both the Forecast and Acutal data. Incremental demand-side resources are not netted out of the Forecast, but are incremental to the base forecast. Howeverever, Incremental demand-side resources can be triggered by many mechanisms. Direct control is only one way to initiate Incremental demand-side resources. Some Incremental demand-side resources are triggered by "rules." For example, demand-side resources may be initiated whenever some triggering parameters are met, e.g., Load exceeds 96% of Forecast peak, or temperature exceeds 90 degrees prior to 4 critical super peak hours, or by an Economic Demand Response. These demand-side resources are not dispatched in the same strict sense as direct control initiation from a Control Center. Yet they are controllable by predetermined "rules." Please define the terms controllable and dispatchable. One definition that might be used is:Definition of Controllable and Dispatchable - Demand-side resource technologies defined by the Planning Coordinator or Planning Authority that are not netted from Forecasts and Actuals. 2) New Technologies - It is not entirely clear how this standard treats evolving, newer technologies. For example, it is not entirely clear how the standard interacts with load shifting technologies, such as cool storage and battery storage; or rechargeable

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	electric vehicles; or Smart Grid? The drafting team should add a further clarifying requirement for the Planning Coordinator or Planning Authority to work with the Applicable Entities to delineate exactly which technologies are to be included and excluded, such as1.X.X The Planning Coordinator or Planning Authority will work with its Applicable Entities to define in advance the list of technologies which are to be included in the Dispatchabe and Controlable category of demand-side resources and how they are to be modelled. 3) Add the following Standard Definitions: Economic Demand Response (EDR) - EDR is demand-side resources that cause specific changes in the Total Internal Demand in support of system reliability based on their response to specific pricing signals, e.g., 4 hour super-peak pricing. Dispatchable - Demand-side resources that are capable of modifying their Total Internal Demand in response to Applicable Entity instructions.
Response: 1) The SDT believes that "controllable and dispatchable" is flexible enough to account for multiple means of implementing DSM programs, while maintaining the intent of only collecting data within this standard on DSM programs that affect BES reliability. **2) The SDT believes that new technologies are expected to meet the definition of "controllable and dispatchable" or be embedded within forecast of Total Internal Demand.** **3) The SDT believes that the current definition included in this standard provide sufficient clarity that additional definitions are not necessary.**	
Exelon	Exelon appreciates the responsiveness of the Drafting Team to comments respecting the role of the LSE's.
Response: The SDT thanks you for your affirmative response and comment.	

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Florida Municipal Power Agency	FMPA has recommended retirement of these standards in accordance with P81, and in alignment with IERP recommendations. The SDT has disagreed, but has not provided sufficient technical justifaction for the existence of a standard.In the SDT's consideration of comments (which by the way does not mention the IERP recommendations to retire these standards), the SDT uses the following reasons to justify a standard:"First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.2 The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.""Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners to obtain the data from a neighboring entity."These are very weak reasons that do not provide sufficient justification for a standard.First, NERC and RE assessments are not included within the perview of standards. FPA Section 215 section (d) contains the legislation for standards; assessment are included in FPA Section 215 section (g) and are separate from standards in the regulatory construct. Hence, the first "reason" to justify a standard does not provide any justification whatsoever.Second, what are the "reliability purposes" of a PC or BA that would supposedly be facilitated through this effort? There is nothing regarding the BA; there are no Planning Horizon requirements of the BA that involve a planning horizon load forecast, so, there is no reliability purpose of this standard for a BA. The SDT seems to forget that operating horizon load forecasts are already provided in other standards (IRO-010, TOP-002). And the SDT provides no technical justification as to why sharing a planning horizon load forecast with neighbors provides any improvement to reliability. So, to FMPA's reasoning, it really boils down to the TPL standard(s) and whether a planning horizon load forecast is significant enough to the TPL standards to meet the Section 215 thresholds for "reliable operation". That is, from the definitions of Setion 215:"The term `reliability standard' means a requirement,

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	approved by the Commission under this section, to provide for reliable operation of the bulk-power system.””The term `reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”A planning horizon load forecast does not provide for “reliable operation” as defined in Section 215. It provides to the TPL standards just a good guess as to what the future load might be in a sampled hour, allocated to individual substations in the model, combined with a generation dispatch that is highly unlikely to occur in real life. The purpose of TPL-001-4 is to: “Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.” In other words, to study reasonable worst case conditions so that we plan a system that can be operated. A planner can establish reasonable worst case conditions without a load forecast provided by someone else using a number of factors such as high load growth cases correlated with hogh economic growth projections for a region, severe weather, etc.Some might say that accuracy of such a forecast is important; but, a forecast is just that, a guess at the future. We cannot know what the weather will be like, we cannot know what the economy is going to do in the future and how that drives load, we cannot know how load growth will vary by sector, we cannot know how load growth will vary from substation to substation, we cannot know the penetration of conservation and DSM programs, etc.. As such, an accurate load forecast is impossible and all we know is that what we forecast will be wrong. This does not mean that it is not important to perform load forecasts for planning purposes, it just does not rise to the signifance of needing to be regulated by standards and instead data requests are sufficient. Hence, the existing standards ought to be retired and replaced with data requests.Also, most PCs are also TSPs, and most TSP OATTs require their network service customers to provide a load forecast; hence, even if the SDT believes, against the IERP recommendations, that there is sufficient technical justification to require a regulatory construct for data collectionof

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	load forecasts, most of those load forecasts are already being collected through the regulatory construct of the OATT. What is not collected through OATTs is certainly inconsequential to BPS reliabilityIn addition, the SDT makes a strange statement in the consideration of comments that says: “(r)eplacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes.” FMPA fails to see how a data request would not provide such a mechanism, and in fact, having a single database for the continent ought to improve such sharing. For instance, in Florida, each utility submits to the FPSC a 10 year site plan with load forecast data that is then made available to other utiltiies in Florida; making the data even more transparent through the FPSC’s collection.It seems to FMPA that the SDT has not given enough consideration to the IERP and other industry expert recommendations to retire these standards. The SDT has not provided sufficient technical justification as to why it disagrees with the Independent Experts except to say that it makes NERC’s and the RE’s life easier and it fulfills an unidentified BA and PC “reliability purpose”, and a nebulous sharing of data purpose. This seems to FMPA like a “brush off” to important recommendations made by multiple experts in the industry that deserves more careful consideration and deliberation.
Response: As discussed in previous responses to comments, the SDT has concluded that the standard is necessary to help ensure that the owners and operators of the BES, as well as the ERO, have complete and accurate Demand and energy data necessary to support the development of reliability assessments. These reliability assessments are vital to ensuring the reliable real-time operation of the BES as these assessments provide owners and operators the necessary information to help ensure resource adequacy. As opposed to a 1600 data request, the standard provides an efficient and enforceable mechanism to collect this data from all applicable users, owners and operators of the BES and also provides entities with a reliability need for such data, a mechanism to directly request such data from other registered entities.	
SPP Standards Review Group	In the standard: 1) There is a concern surrounding the ‘Applicable Entities’ Which includes ‘Resource Planners’ however; R1 1.1 indicates the request should list the TPs, BAs, LSEs and

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	DPs. We would request clarity to be provided regarding the Resource Planner's role in reference to R1 1.1. 2) We have a concern that the definition of 'Total Internal Demand' in the proposed standard and the (2014) Long Term Reliability Assessment (LTRA) are not consistent. Our request to the drafting team would be to review the definitions in both documents and ensure that we have consistency and efficiency for the applicable standard and assessment process. 3) There is concern surrounding the 'Applicable Enities' and their reporting of data in Requirment R4. The requesting and providing of data to the direct Planning Coordinators or Balancing Authoritys will be covered in Requirments R1 and R2. However; the concern would be having 'Applicable Enities' to provide this same data numerous time to other Planning Coordinators or Balancing Authoritys who are not in the direct reporting process. We feel that the sharing of the data could be more effiecient if the neighboring Planning Coordinators or Balancing Authoritys would make the data request from the direct Planning Coordinators or Balancing Authoritys who originally requested the data. 4) R1, VSLs – Revise the Lower VSL to read 'The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1 late but within 6 days of the date indicated in the timetable provided pursuant to Requirment 1, Part 1.2.' The Moderate VSL would be revised to read 'The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1 more than 6 days but within 11 days of the date indicated in the timetable provided pursuant to Requirement R1, Part 1.2.' The High VSL would be modified in a similar manner substituting 11 days and 15 days for the 6 days and 11 days, respectively, in the Moderate VSL. 5) Typos/grammatical :

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	R1, Part 1.2 and other places within the standard where a specific number of calendar days are specified - 30-calendar days (hyphenate) R1, Parts 1.3.1, 1.3.2, 1.4.1, 1.4.3 - Demand instead of Demands R1, Part 1.5 - Delete 'about' at the end. The end of Part 1.5 would then read '...summary explanations, as necessary:' In the Rationale Boxes,in R4 and in the VSLs, capitalize Part when it is associated with part of a Requirement such as Requirement 1, Part 1.3.2. Whitepaper on MOD C Standards: We again suggest that references to the Bulk Power System in the Whitepaper be made to the Bulk Electric System instead. In Footnote 1 at the bottom of Page 5, replace 'has' with 'have' such that it reads '...NERC and the Regional Entities have the authority...' In the 6th paragraph on Page 5, (2) is akward at best. Perhaps it should read '...(2) the sharing of such data among Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners once obtained from a neighboring entity.' As suggested in the standard, when referenced with a Requirement, Part should be capitalized.
Response: 1) The role of the RP within the standard is an entity which may require the data in Requirement R1 parts 1.3 through 1.5 and may request this data pursuant to Requirement R4. **2) Reconciling the differences between the two definitions will be done outside the standard by the NERC RAS.** **3) The SDT is providing an equally effective and efficient method for responding to a FERC directive, which required the collection of temperature and humidity. The SDT believes that requiring hourly temperature and humidity values would provide no value since there are differing methods used to weather normalize Demand. The method an entity would use to weather normalize their actual data should be dependent on their unique system configuration.**	

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4) The SDT does not believe that the language you have proposed provides any additional clarity. **5) R1, part 1.2 – The style that is being used in this standard is the same that has been used in other results-based standards.** **R1, parts 1.3.1, 1.3.2, 1.4.1, 1.4.3 – The SDT is asking for more than one hour of data and therefore believes that the plural version is appropriate.** **R1, part 1.5 – The SDT agrees and has removed the term.** **Rationale Boxes in R4 and in the VSLs - The style that is being used in this standard is the same that has been used in other results-based standards.** **Whitepaper** **The SDT agrees and has changed the phase “Bulk Power System” to “Bulk Electric System”.** **The SDT has modified the footnote to use the term “have” instead of “has”.** **6th paragraph on Page 5 – The SDT has modified the sentence you have referenced.**	
Florida Power & Light	It is currently unclear if the different reporting requirements will result in FPL no longer being able to point to its Ten Year Site Plan filing with the FPSC as the place where all of the data currently requested in MODs 16-19 and 21 are found. One example is the apparent change in load forecasting regarding weather-normalized load.
Response: This standard establishes new reporting requirements which may require modifications to your current process.	
Northeast Power Coordinating Council	No comments.
Response: Thank you for your affirmative response.	
Oncor Electric Delivery Company LLC	Oncors Commercial Load Management Standard Offer Program (CLMSOP) was developed to pay incentives to energy efficiency service providers (e.g., contractors, energy service companies, retail electric providers, or customers) for load curtailments of electric consumption on short notice during the summer peak period. Incentives are based on verified demand savings that occur at an Oncor distribution customer’s site as a result of

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	a curtailment. Oncor's CLMSOP is a voluntary program, hence it is not controllable and dispatchable. The program requires service providers to be prepared to participate in up to 25 curtailment hours during the summer peak period. A called curtailment will occur as requested by Oncor. Oncor will comply with ERCOTs requests to deploy the program during or in anticipation of an ERCOT Energy Emergency Alert. Oncor will notify service providers of a called curtailment at least one hour prior to the start-time of the curtailment. Only Oncor authorized personnel can issue notices to service providers to initiate a curtailment. Regarding 1.3.4, Oncor requests the following changes to allow the inclusion of voluntary Demand Side Management programs: Monthly and annual peak hour controllable and dispatchable, or voluntary Demand Side Management under the control, supervision, or direction of the System Operator or other company representative in megawatts for the prior calendar year. Three values shall be reported for each peak hour curtailment event: 1) the committed megawatts (the amount under control, supervision, or direction), 2) the dispatched or requested megawatts (the amount, if any, activated for use by the System Operator or other company representative), 3) the realized megawatts during curtailment events (the amount of actual demand reduction), 4) type of program (controllable and dispatchable, or voluntary), and 5) System Operator defined monthly and annual peak hours. Regarding 1.4.5, Oncor's CLMSOP is implemented on a yearly basis and is only projected one year into the future. We recommend the following changes: Total and available peak hour forecast of controllable and dispatchable, or voluntary Demand Side Management (summer and winter), in megawatts, under the control, supervision, or direction of the System Operator or other company representative for their applicable forecasting period. Regarding 1.5.2, Oncor requests the following changes to allow the inclusion of voluntary Demand Side Management programs. We recommend the following changes:

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	The Demand and energy effects of controllable and dispatchable, or voluntary Demand Side Management under the control, supervision, or direction of the System Operator or other company representative. Regarding 1.5.4, Oncor requests the following changes to Reporting Requirement 1.5.2 to allow the inclusion of voluntary Demand Side Management programs : How the controllable and dispatchable, or voluntary Demand Side Management forecast compares to actual controllable and dispatchable, or voluntary Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.
Response: The SDT believes that "controllable and dispatchable" is flexible enough to account for multiple means of implementing DSM programs, while maintaining the intent of only collecting data within this standard on DSM programs that affect BES reliability. Whether the program should be reduced would be determined by ERCOT.	
Cooper Compliance Corp	Particular to Standard MOD-031, the drafting team should consider requiring BAs and PCs to post the data request on their website and distribute the request to other entities one (1) year in addition to sending a reminder (1) quarter year (3 months) prior to the due dates. Thirty (30) day data requests are time consuming and often these requests are made to the incorrect person. Furthermore, the detail for what should be received in the request should be stated by the BA or PC and not by the Standard.
Response: The SDT believes that the phrase "issue a data request" indicates that this will be in writing. Furthermore, the SDT does not feel that this standard needs to be as prescriptive as you suggest. **This standard establishes a scope of data that may be requested every year. The PC or BA may request additional data that is outside the scope of this standard.**	
PJM Interconnection	PJM supports the draft standard and appreciates the drafting team implementing PJM's recommended changes to the definition of Total Internal Demand and R4. Based on the

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	revised draft, PJM will vote in the affirmative.Additionally, PJM suppports the SRC's comments and has signed onto them.
Response: Thank you for your affirmative response and comment.	
Electric Reliability Council of Texas, Inc.	1) Please consider using IRO-010-1a R1 as a guideline for allowing an reliability entity to ask for what is required without being so prescriptive and yet limiting to the requestor. This standard is very similar in nature to IRO-010-1a and should be consistent with such a format. 2) M1, M2, M3: Propose deleting prescriptive elements in measures. If the data request needs to be dated or the format has to be a certain way, then it should be in the requirement and not in the measure. Preferable means of evidence can be listed in the RSAW but are not requirements. Recommend for most instances to include "or other equivalent evidence" to allow flexibility for a responsible entity and the auditor to accept such means of evidence. 3) R4: Delete "with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System". This statement is ambiguous and leaves language open to interpretation. 4) Recommend just including TP and RP in R1 and delete R4 to simplify. There should not be a distinction between how or what you provide to a reliability entity that has reliability tasks to perform. If you simplify R1 to be consistent with IRO-010-1a, this makes the standard much simpler and streamlined. 5) R4.1: Applicable entities should be required to provide data without exception and therefore propose removing language that would allow entities to explain why they will not provide requested data. 6) M4: Removed language related to R4.1 that would allow for explanation for non-submittals 7) Table of Compliance Elements: Recommend modifying the VRFs and VSLs to that which is consistent with IRO-010-1a. Issuing a request for data is not a medium VRF, nor providing to the RE when applying the violation risk factor guideline.

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	8) Similar to IRO-010-1a, it is possible to allow for so different variations to graduate the VSLs in severity consistent with the VSL guideline document. 9) General comment is that with the modifications to the definition to DSM and the introduction of Total Internal Demand, NERC and or the SDT should review the potential impact or necessity for modifications to other existing NERC Reliability standards which use those terms or terms that are included in the make up identified in the definition. An example would be the use of interruptible load vs DSM in other standards. 10) Also, it is unclear if there are controls that limit the double counting of load under Firm Demand and or controllable and dispatchable DSM load as load by definition is Firm untila certain criteria is reached allowing the use of the DSM load.

Response: 1) The SDT does not believe that the standard is being prescriptive but rather limits the amount of data that can be requested under this standard. Other data can be requested but it is not subject to this standard.

2) The measures describe the evidence necessary to demonstrate compliance, and the SDT does not believe the current measures are too prescriptive.

3) The SDT believes that the language is not ambiguous and does not leave language open to interpretation. Also, the current language is necessary to allow the requester and the applicable entity to evaluate an extraneous request.

4), 5), & 6) The SDT believes that the deletion of R4 is not an option because it requires sharing of data pursuant to R1 parts 1.3 through 1.5 with other entities. Furthermore, PC's, BA's, TP's and RP's may request the same data pursuant to R4 but must demonstrate a reliability need, which the SDT believes is an important criterion and does not exist in R1.

7) SDT cannot justify a low VRF.

8) Concerning your comment about the VSL for Requirement R1, the SDT does not believe that the requirement is open ended rather the SDT feels that using the phrase "any or all" in parts 1.3, 1.4 and 1.5 provides flexibility to allow for instances when a requestor may not have a reliability need to collect all of the data outlined within the standard. Using this approach, the SDT does not believe that it can write a VSL for parts 1.3, 1.4 and 1.5. Since the inclusion of some or all of the data listed in these parts is optional, then it would not make sense to have VSL's requiring some or all of the data. Removing parts 1.3, 1.4 and 1.5 from the VSL leaves only parts 1.1 and 1.2. If either of these two parts are left out of a data request then either the data owners or the

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timeline for responding would be missing and thus make the data request invalid. This turns the requirement into a binary (yes or no) type of requirement which according to the VSL guidelines carries only a severe level. **9) DSM definition change impact on other standards (see earlier comment and Attachment 1 of the standard's Implementation Plan)** **10) The SDT believes that R1.5 part 1.5.1 (Demand forecast methods and assumptions) provides the approach for ensuring aggregate load is not double counted.**	
Georgia Transmission Corporation	R1 states that the PC and BA "shall develop and issue a data request", but in R4 includes the TP and RP (in addition to the PC and BA) as giving a "written request for the data". We are suggesting that the drafting team either add TP and RP to R1 or remove them from R4.
Response: R4 allows the TP's and RP's and other PC's and BA's to request the data pursuant to R1 parts 1.3 through 1.5 if they demonstrate a reliability need, which the SDT believes is an important criterion and does not exist in R1.	
ReliabilityFirst	ReliabilityFirst votes in the affirmative for the MOD-031-1 standard but votes in the negative for the non-binding poll. ReliabilityFirst submits the following comment related to the VSL for Requirement R1.1. The VSL for Requirement R1 only speaks to failing to include either the entity(s) necessary to provide the data (Part 1.2) or the timetable for providing the data (Part 1.2). ReliabilityFirst notes that there is no mention of an entity failing to meet the intent of Part 1.3, Part 1.4 or Part 1.5. Failure to include these Parts in the data request may result in a possible violation and hence need to be noted in the VSLs. ReliabilityFirst recommends including a Moderate VSL such as: "The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include items in Requirement R1, Parts 1.3, Parts 1.4 or Parts 1.4 in the data request."

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Response: Concerning your comment about the VSL for Requirement R1, the SDT does not believe that the requirement is open ended rather the SDT feels that using the phrase "any or all" in parts 1.3, 1.4 and 1.5 provides flexibility to allow for instances when a requestor may not have a reliability need to collect all of the data outlined within the standard. Using this approach, the SDT does not believe that it can write a VSL for parts 1.3, 1.4 and 1.5. Since the inclusion of some or all of the data listed in these parts is optional, then it would not make sense to have VSL's requiring some or all of the data. Removing parts 1.3, 1.4 and 1.5 from the VSL leaves only parts 1.1 and 1.2. If either of these two parts are left out of a data request then either the data owners or the timeline for responding would be missing and thus make the data request invalid. This turns the requirement into a binary (yes or no) type of requirement which according to the VSL guidelines carries only a severe level.	
Salt River Project	SRP has no issues with this draft.
Response: Thank you for your affirmative response.	
Wisconsin Public Service Corporation	1) Suggested Language Modification for R1.5.2 (to clarify what is meant by effects): The total demand (Mw) and energy (Mwh) of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator. 2) Suggested Language modification for R1.5.4 and R1.5.5 (clarification of annual): 1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual annual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted. 1.5.5. How the peak load forecast compares to actual annual peak load for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.
Response: 1) The intent of the SDT is to allow a narrative explanation to be sufficient in response to a request pursuant to R1 part 1.5.2; therefore "effect" is sufficient.	

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2) The SDT believes that the current language allows for explanations on monthly, seasonal, and annual comparisons of DSM and load, which is the intent of the SDT.	
Duke Energy	The proposed definition of Demand Side Management appears to be overly broad, and may lead to certain activities or programs to be labeled as Demand Side Management that the SDT did not intend.Duke Energy suggests a re-wording of the proposed definition of Demand Side Management (DSM) to the following: "Demand Side Management: All real-time activities or programs undertaken by any applicable entity to achieve a reduction in Demand." The addition of the phrase "real-time" adds needed clarity as to the types of activities or programs to be undertaken in the definition, and narrows the scope to avoid unintended inclusions.
Response: The SDT believes that the addition of "real-time" would inappropriately limit the scope of DSM programs. Passive, non-operator controlled, DSM is intended to be included in the broad definition of DSM. The reporting requirements within the standard narrow the scope of DSM to controllable and dispatchable programs.	
ISO/RTO Standards Review Committee	The SRC asks for clarification regarding the scope of the proposed standard. Based upon the standards being proposed for retirement (MOD-016,17, 18, 19, and 21) the SRC asks if this standard is designed specifically for the Long Term Planning (LTP) Horizon or is it designed for both Long-term and Operations Planning? The SRC raises the question because: o If the proposal were only for Long Term Planning, then the SRC would note that in the Functional Model BAs are not involved in LTP, and the BA is therefore not an Applicable Entity. o If the proposal were for both LT Planning and Operations Planning (as implied by having both PC, TP and BA), then it would add clarity to add the Operations Planning Horizon for R1 if both were to need the same listed information; or better

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	to add a standard or a requirement to address the specific data needs of the BA in developing a Day-Ahead operating plan. On the other hand, if the reason for including the BA is to recognize the LTP obligations imposed on the WECC BAs, then the SRC would ask that the SDT explicitly acknowledge that point - e.g. either as a footnote, or in the Applicability section. Please note, CAISO abstained from these comments.
Response: SDT believes that a footnote for BA (BA*) in R1 stating that R1 is applicable to WECC BA's performing additional duties outside of the Functional Model. BA's (non-WECC) may collect the data pursuant to R4 if reliability need is demonstrated.	
JEA	This is purely a data request standard and should be eliminated in accordance with the P81 project.
Response: As discussed in previous responses to comments, the SDT has concluded that the standard is necessary to help ensure that the owners and operators of the BES, as well as the ERO, have complete and accurate Demand and energy data necessary to support the development of reliability assessments. These reliability assessments are vital to ensuring the reliable real-time operation of the BES as these assessments provide owners and operators the necessary information to help ensure resource adequacy. As opposed to a 1600 data request, the standard provides an efficient and enforceable mechanism to collect this data from all applicable users, owners and operators of the BES and also provides entities with a reliability need for such data, a mechanism to directly request such data from other registered entities.	
Tennessee Valley Authority	TVA appreciates the efforts of the Standards Drafting Team to develop this replacement standard and address FERC's directives. As stated in our comments on the second draft, it is unclear if the purpose of the replacement standard is to facilitate demand and energy data collection by the registered entities who have a reliabiliy related need to obtain the data for the purpose of making BES infrastructure decisions (the TP/TO and RP/GO), or if the end purpose is to provide data to the Regional Entity / ERO for the purpose of producing regional or NERC wide reliability assessments. With the latest draft, it seems more evident that the drafting team is working toward the latter. That being the case, we believe a "paragraph 81" review leading to the retirement of these standards is the

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	more appropriate course. Furthermore, the proposed standard would only address the demand and energy data aspect of the regional and NERC level assessment needs, with no corresponding standard/requirements for the collection of resource data. If the standard moves forward as currently drafted, can a PC or BA elect not to request any (or some) data under R1 and when requested by the Regional Entity to provide the data (R2) respond that it has not collected it? A proposed solution is for the drafting team to revise the purpose of the standard to be - “To enable Transmission Planners and Resource Planners to define and collect the Demand, energy and related data necessary to perform planning studies that support future intrastructure build decisions by the Transmission Owner and Generation Owner.” If the drafting team moves forward with this focus, the requirements will need further work. The standard’s applicability could be revised to include a “Demand/Energy Data Entity” (reference PRC-006-1 for similar precedent - “UFLS Entity”) that can include the LSE, DP, BA or TO. We believe a standard developed under this purpose, while still seeking to address FERC’s directives, would be of more reliability benefit than a standard that focuses on partial data collection needed for Regional Entity / ERO assessments.

Response: 1) As discussed in previous responses to comments, the SDT has concluded that the standard is necessary to help ensure that the owners and operators of the BES, as well as the ERO, have complete and accurate Demand and energy data necessary to support the development of reliability assessments. These reliability assessments are vital to ensuring the reliable real-time operation of the BES as these assessments provide owners and operators the necessary information to help ensure resource adequacy. As opposed to a 1600 data request, the standard provides an efficient and enforceable mechanism to collect this data from all applicable users, owners and operators of the BES and also provides entities with a reliability need for such data, a mechanism to directly request such data from other registered entities. The SDT believes that the intent of the latest draft is to facilitate data collection regardless of whether it is for NERC wide assessments or for another reliability purpose.

2) **The purpose of the language “as necessary” in R1 is to provide the PC or BA from having to issue a data request when the data is already available to them. This does not allow the PC or BA to deny a request for data by the RE pursuant to R3.**
3) **Since the SDT did not agree with your comments (see 1) and 2) above), the SDT does not believe a solution is necessary.**

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DTE Electric	We have no issues with the draft of MOD-031-1 standard but wanted to bring to your attention that under M3 (page 9) "Authority" is mispelled.
Response: Thank you for your affirmative response. The misspelling has been corrected.	
Independent Electricity System Operator	We submitted a couple of comments expressing concerns over the proposed VRFs and VSLs for certain requirements but have not seen a response from the SDT addressing these concerns, nor do we find changes to the draft standard that address these concerns. We'd therefore reiterate our comments as follows: 1. R1: In the sentence "Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data shall develop and issue a data request to the applicable entities in their area." Suggest to change "their" to "its" before "area". 2. R1: The wording suggests that the PC and BA shall also distribute the list of applicable entities identified in part 1.1 as part of the data request. Please clarify whether this is the intent otherwise the requirement will have to be reworded. 3. R1, part 1.5.5: Suggest to change "peak load" to "Peak Demand" and change "actual load" to "actual Demand". 4. R4: The SDT's response to our last comment that the sentence "This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1." Was that it provided clarification. While we agree it does serve that purpose, we continue to disagree with the need to include this statement in Requirement R4. We reiterate our position that the second sentence of R4 is unnecessary and should be deleted and propose the following alternative wording for R4: "Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator or Balancing Authority other than its Planning Coordinator or Balancing Authority, or a Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability

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	assessments of the Bulk Electric Sysytem [sic], provide or otherwise make available that data to the requesting entity. Also, please correct the word “sysytem” to “system”. 5. R4: The first bullet has been modified substantially and now introduces a time limit for provision of the requested data. Since this first bullet now represents a requirement, we believe it appropriate to remove the bullet and make it Part 4.1. We therefore propose that the last part of R4 should read as follows, “Unless otherwise agreed upon, the Applicable Entity shall provide:”, and Part 4.1 should read “The requested data...”. The second bullet of R4 may remain unchanged. 6. R1: Requirement R1 is assigned a MEDIUM VRF. This appears to be inconsistent with the LOW VRF assigned to R1 of MOD-032, which stipulates the requirement for the Planning Coordinator and Transmission Planner to develop the modeling data requirements and reporting procedures. The two requirements appear to be requiring the specification of data and collection procedure required for reliability assessment, yet their VRFs differ by a level. We suggest the SDT to consult the MOD-032 and MOD-033 SDT to confirm the difference based on supporting rationale, or to adjust either VRF to achieve consistency. If the SDT holds the view that the MEDIUM VRF assignment is appropriate, we are unable to find any supporting document that provides the justification for this assignment. If the justification document is posted somewhere and we’ve looked this, please point us to the place where it is posted. 7. There is only one SEVERE VSL for the Planning Coordinator or the Balancing Authority failing to include the entity(s) necessary to provide the data (Part 1.1) or the timetable for providing the data (Part 1.2), but there are no VSLs for the conditions when these entities fail to specify any of Parts 1.3 to 1.5. We suggest to add the VSLs for these conditions to meet the NERC and FERC VSL guidelines. If the SDT holds the view that VSLs for violating Parts 1.3 to 1.5 do not need to be provided, we are unable to find any supporting document that provides the justification for not providing these VSLs. If the justification

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	document is posted somewhere and we've looked this, please point us to the place where it is posted.
Response: 1) The SDT will revise "their" to "its". **2) Yes, the intent of the SDT is that the data requesters identify the data owner ("Applicable Entities") in a data request.** **3) The SDT will revise "load" to "Demand" in R1.5.5.** **4) The SDT does not agree with your proposed revision and believes that the current language is necessary to ensure an applicable entity does not attempt to avoid its responsibilities pursuant to R2. The SDT has revised the misspelling of "System".** **5) The SDT believes that the "bullets" are only clarifying the requirement and are not placing any further requirement on an entity as part 4.1 does.** **6) The majority of the requirements in the current standards are Medium, and the SDT had no justification for changing.** **7) Concerning your comment about the VSL for Requirement R1, the SDT does not believe that the requirement is open ended rather the SDT feels that using the phrase "any or all" in parts 1.3, 1.4 and 1.5 provides flexibility to allow for instances when a requestor may not have a reliability need to collect all of the data outlined within the standard. Using this approach, the SDT does not believe that it can write a VSL for parts 1.3, 1.4 and 1.5. Since the inclusion of some or all of the data listed in these parts is optional, then it would not make sense to have VSL's requiring some or all of the data. Removing parts 1.3, 1.4 and 1.5 from the VSL leaves only parts 1.1 and 1.2. If either of these two parts are left out of a data request then either the data owners or the timeline for responding would be missing and thus make the data request invalid. This turns the requirement into a binary (yes or no) type of requirement which according to the VSL guidelines carries only a severe level.**	
Western Electricity Coordinating Council	WECC thanks the drafting team for the revisons to several of the definitnions and changes to the requirements that we identified and suggested in the last round of comments. WECC believes this standard is an improvement over the currently-effective standards it is intended to replace and for that reason WECC will be voting YES for this version of the standard. 1) However, as noted in our earlier comments, WECC still has concerns related to the 75-day time frame identified in Requirement R3. Giving the PC or BA up to 75 days to provide the data collected under R2 to the applicable Regional Entity WILL NOT WORK under the schedule currently used at NERC. For example, this year (2014) NERC did

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	not distribute their data request to the Regional Entities until January 7, 2014. Even if the Regional Entities could have requested the data collected under R2 from the PC or BA on the same day and the PC or BA could have turned the request around and sent it to the applicable entitis on the same day, per the language of R1 and R3, it would not be due to the Regional Entity until April 20, 2014 (30 days for applicable entity to respond plus 75 days for the PC or BA to provide the data to the Regional Entity). However, this year the due date for submitting the summer assessment to NERC was March 14. Unless NERC distributes their request to the Regional Entities much earlier, or the Regional entities and the PC or BA agree to a shorter period, the data is not available to the Regional Entity until well after the due date back to NERC. WECC recognizes that a shorter period may be "agreed upon" but because of the language of Requirement R3, the PC or BA could push for 75 days to provide the data. 2) A second concern WECC has voiced in earlier comments is that Requirement R1, part 1.4.3 asks for Peak hour forecast Total Internal Demands (summer and winter) for 10 calendar years. Part 1.4.4 asks for annual Net Energy for 10 years. To do probabilistic studies, monthly peaks and energy are needed. WECC would like to see the language in parts 1.4.3 and 1.4.4 changed to require monthly peak and monthly energy. WECC has submitted these concerns during earlier comment periods and the drafting team did not address them in their summary response to comments. WECC requests that the drafting team either implement these suggested changes or clearly communicate in the summary response to comments why the suggested changes are not necessary. Without this information WECC will consider voting NO on the next additional ballot or final ballot and suggesting that entities in the West vote NO as well.

Response: 1) The 30 calendar day requirement for applicable entities is within the 75 calendar day time period for the PC and BA to respond to the RE. So in your example, "April 20th" is "March 23rd", as intended by the SDT. Also, the RE may request the data to be submitted earlier, but applicable entities will not be in violation of the standard if the earlier deadline is not met. The SDT has discussed this issue with NERC staff and the intent is for the data request to be issued earlier so this will not be an issue in the future.

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2) The RE may request additional years of monthly peak data; however this would be outside the scope of the current standards and the new standard. This standard is written to align with the current standards.	
Seminole Electric Cooperative, Inc.	While Seminole generally supports the language contained in the proposed reliability standard, there are still some concerns as outlined below: 1. Requirement R3 states that the PC or BA shall provide certain data within “75 days” of receiving such a request. This requirement does not specify whether the days are “calendar” or “business”. Because the SDT uses “calendar” days in other places throughout the document, the implication is that R3 is meant to refer to business days due to the omission of the word “calendar”. Please revise the proposed language to clearly specify the SDT’s intent. 2. Requirement R4.1 states that Applicable Entities must respond within 30 calendar days of a request. However, if an entity requests data and then the Applicable Entity sends a follow-up request for the reliability need for this data, the Applicable Entity’s response is now contingent upon the timeliness of the response from the requesting entity. This Requirement appears to lack flexibility when a requesting entity does not provide a sufficient reliability need for the data in their initial request. Seminole requests that such flexibility be provided in the Requirement, e.g., 30 calendar days from receipt of a request whose reliability need has been sufficiently communicated.
Response: 1) The SDT has made this revision. **2) The SDT believes that dispute resolution process occurs outside the standard, and if a new request is required, the clock refreshes.**	

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Modesto Irrigation District	I want to vote NO on MOD-031-1. The reason is because of the language in Section B R1 1.3.2. I don’t believe we should be skewing the actual demand data recorded, that is then subsequently used in our analysis work.
Response: 1) **The SDT does not understand your comment. Applicable Entities have to submit both actual and weather normalized data if applicable.**	
Omaha Public Power District	OPPD recommends that the SDT consider revising DSM description used in Requirement R1 part 1.3.4 to be consistence with the description of DSM used in the NERC Long-Term Reliability Assessment (LTRA).
Response: 1) **Requirement R1 part 1.3.4 further categorizes DSM into three buckets which the SDT intended to be reported through the standard. We believe that the definition of DSM is still aligned with the NERC LTRA.**	

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. The SAR and supporting package were posted for comment (July 2013).
2. First posting of the draft standard for a 45-day comment period and parallel ballot (July/August 2013).
3. Second posting of the draft standard for a 45-day comment period and parallel ballot (October/November 2013)
4. Third posting of the draft standard for a 45-day comment period and parallel ballot (February/March/April 2014)

Description of Current Draft

This is the final posting of the proposed draft standard. This proposed draft standard will be posted for a 10-day final ballot.

Anticipated Actions	Anticipated Date
Final ballot	April-May 2014
BOT adoption	May 2014

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Total Internal Demand: The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

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: Demand and Energy Data**

2. **Number:** **MOD-031-1**

3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "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 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

Rationale for R2: This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

Rationale for R3: This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity’s obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and

- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

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	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in

			Requirement R1, but did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to

			Requirement R2, but did so after 75 days from the date of request but prior to 81 days from the date of the request.	Requirement R2, but did so after 80 days from the date of request but prior to 86 days from the date of the request.	Requirement R2, but did so after 85 days from the date of request but prior to 91 days from the date of the request.	91 days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

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. The SAR and supporting package were posted for comment (July 2013).
2. First posting of the draft standard for a 45-day comment period and parallel ballot (July/August 2013).
3. Second posting of the draft standard for a 45-day comment period and parallel ballot (October/November 2013)
4. ~~3.~~4. Third posting of the draft standard for a 45-day comment period and parallel ballot (February/March/April 2014)

Description of Current Draft

This is the final~~third~~ posting of the proposed draft standard. This proposed draft standard will be posted for a 10~~45~~-day final~~formal comment period and parallel~~ ballot.

Anticipated Actions	Anticipated Date
~~45-day Comment Period with Parallel Ballot~~	~~February-March 2014~~
Final ballot	April-May 2014
BOT adoption	May 2014

~~**Effective Dates**~~

~~**MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.**~~

Version History

Version	Date	Action	Change Tracking
1	TBD	Adopt MOD-031-1	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms used in Reliability Standards (Glossary)~~Reliability Standards Glossary of Terms~~ are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Total Internal Demand: The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

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: Demand and Energy Data**

2. **Number:** **MOD-031-1**

3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. **Applicability:**

   4.1. **Functional Entities:**

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "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 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date**

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform ~~the~~reliability studies and assessments, authority is needed to collect the applicable data.

The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they ~~must~~ identify the entities that must~~to~~ provide the data (Applicable Entity in part 1.1), ~~and that the entities providing~~ the data ~~must know what they are~~ to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (~~[~~e.g., temperature, humidity or wind speed~~]~~), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its~~their~~ area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data (“Applicable Entities”).

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,~~ about~~:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand~~load~~ forecast compares to actual Demand~~load~~ for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

Rationale for R2: This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

R2. Each Applicable Entity~~,~~ identified in a~~the~~ data request~~,~~ shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

Rationale for R3: This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authori~~r~~ty, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

Rationale for R4: This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric Sys~~y~~tem, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and

- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

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	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in

			Requirement R1, but did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	Requirement R1 part 1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to

			Requirement R2, but did so after 75 days from the date of request but prior to 81 days from the date of the request.	Requirement R2, but did so after 80 days from the date of request but prior to 86 days from the date of the request.	Requirement R2, but did so after 85 days from the date of request but prior to 91 days from the date of the request.	91 days or more from the date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

> **Demand Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
>
> **Total Internal Demand:** The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.

The defined term "Demand Side Management" is incorporated in the NERC approved standards listed in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand Side Management," it is not anticipated that the proposed revision will have any effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

MOD-031-1 shall become effective as follows:

The first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities 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 twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "Demand-Side Management"

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term "Demand-Side Management"

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

Implementation Plan

Project 2010-04 Demand and Energy Data

Implementation Plan for MOD-031-1 – Demand and Energy Data

Approvals Required
MOD-031-1 – Demand and Energy Data

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

> **Demand Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in ~~request that~~ Demand ~~be reduced~~. ~~Examples of DSM may include, but are not limited to, Direct Control Load Management, Interruptible Load, critical peak pricing (CPP) with control and Load as capacity resources.~~
>
> **Total Internal Demand:** The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable~~the~~ DSM Load and the Load due to the energy losses incurred within the boundary of the metered~~Transmission and distribution~~ system~~s~~.

The defined term "Demand Side Management" is incorporated in the NERC approved standards listed in Attachment 1 of this document. After reviewing the standards incorporating the term "Demand Side Management," it is not anticipated that the proposed revision will have any effect on the standards.

Applicable Entities

Planning Coordinator and Planning Authority

Transmission Planner

Resource Planner

Balancing Authority

Load-Serving Entity

Distribution Provider

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates

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Justification
The 12-month implementation period will provide sufficient time for the applicable entities to develop the necessary process to implement this standard.

Retirements
MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

The current definition of Demand Side Management (DSM) in the NERC Glossary of Terms shall be retired at 11:59:59 p.m. of the day immediately prior to the effective date of MOD-031-1 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term “Demand-Side Management”

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation
EOP-002-3.1 — Capacity and Energy Emergencies
IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection
MOD-016-1.1 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0.1 — Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0 — Reports of Actual and Forecast Demand Data
MOD-019-0.1 — Forecasts of Interruptible Demands and DCLM Data
MOD-020-0 — Providing Interruptible Demands and DCLM Data
MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

Approved Standards Pending Regulatory Approval Incorporating the Term “Demand-Side Management”

BAL-002-WECC-2 — Contingency Reserve
TPL-001-2 — Transmission System Planning Performance Requirements
TPL-001-3 — System Performance Under Normal Conditions
TPL-001-4 — Transmission System Planning Performance Requirements
TPL-002-2b — System Performance Following Loss of a Single BES Element
TPL-003-2a — System Performance Following Loss of Two or More BES Elements
TPL-003-2b — System Performance Following Loss of Two or More BES Elements
TPL-004-2 — System Performance Following Extreme BES Events
TPL-004-2a — System Performance Following Extreme BES Events
TPL-006-0 — Assessment Data from Regional Reliability Organizations
TPL-006-0.1 — Assessment Data from Regional Reliability Organizations

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Demand Data		
Date Submitted:	July 18, 2013		
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC		
Telephone:	609-613-1848	E-mail:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives, incorporate lessons learned, update standards, and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.
Purpose or Goal (How does this request propose to address the problem described above?):
The pro forma standard consolidates the reliability components of the existing standards.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 693, remove ambiguity from the requirements, and incorporate lessons learned.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
An informal development ad hoc group is presenting a pro forma standard that consolidates the existing MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1 and MOD-021-1 into a single standard. The collection of demand projections requires coordination and collaboration between Planning Authorities (also referred to as "Planning Coordinators"), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will enhance the reliability of the BPS. Collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. The pro forma standard requirements are currently placed within a new standard, MOD-031-1.
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.)
Detailed description of this project can be found in the Technical White Paper of this SAR submittal package.

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.

Reliability Functions		
☒	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.
☒	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

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.
☐	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
MOD-001-1a	Available Transmission System Capability

Related Standards	
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None

Regional Variances	
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Compliance Operations

Draft Reliability Standard Compliance Guidance for MOD-031-1
July 3, 2013

Introduction
The NERC Compliance department (Compliance) worked with the 2010-04 Demand Data standard drafting team (SDT) to review the proposed standard MOD-031-1. The purpose of the review was to discuss the requirements of the pro forma standard 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-031-1 Questions

Question 1
In Requirement R2, will the auditor verify 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 sharing of data, the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard.

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

B. Requirements and Measures

R1. The Planning Coordinator or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Loads and Demande Side Management data from applicable entities in their area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities and Distribution Providers that are required to provide the data (“Applicable Entities”).

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts (MW) for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management in megawatts for the prior year.

1.4. A request to p[rovide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load[1], temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to

[1] For the purpose of this standard, the term "controllable load" shall refer to both interruptible load and direct control load management as referenced in FERC Order 693 Para 1267.

Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or
- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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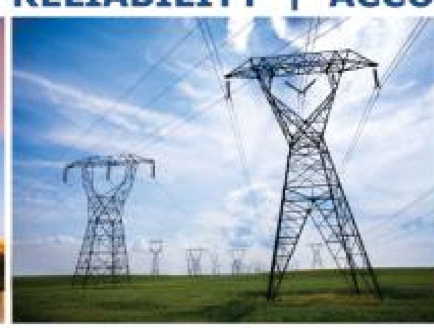
White Paper on the MOD C Standards

MOD-016, MOD-017, MOD-018, MOD-019, and MOD-021

February 14, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the “MOD C” standards), were approved in the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 provides for the documentation of the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 provides for the collection of interruptible demands and direct control load management.
- MOD-020-0 addresses the need to provide interruptible demands and direct control load management data to System Operators and Reliability Coordinators.
- MOD-021-1 provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC’s Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC’s Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

A pure data reporting standard would be a candidate for retirement under Paragraph 81. During the review of the requirements in the current standards, it was not clear whether every Planning Authority (PA) and Balancing Authority (BA) had authority to collect this data from all registered entities in their PA/BA area. Since the data being collected has a reliability purpose in the development of future reliability assessmentseach PA/BA needs the authority to collect this data. In order to specify the scope and limitations of the data collection authority, there was a consolidation of the remaining five MOD C standards into a single standard. The consolidation effort was supported by the industry as the group conducted informal development outreach. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

As detailed below, this document discusses the outstanding directives from FERC Order No. 693 and identifies the applicable requirements in standard MOD-031-1 Demand and Energy Data that address each directive.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of collecting data used in reliability assessments. This document outlines the next generation of these standards and proposes to combine the reliability components of this package of standards into one standard. The remaining requirements in this package would either be retired as administrative or captured as instructional or explanatory in a white paper.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how NERC is addressing each of the outstanding FERC directives assigned to these FERC-approved standards. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

Technical Discussion

The fundamental test for determining the adequacy of the Bulk Electric System (BES) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand projections requires coordination and collaboration between Planning Authorities/Planning Coordinators, Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts—as well as the supporting methods and assumptions used to develop these forecasts—will ultimately enhance the reliability of the BES. Consistent documenting and information-sharing activities will also improve the efficiency of planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and Demand-Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

A second alternative to addressing data requirements in the absence of a standard is the implementation of either a Section 800 or Section 1600 data request. The SDT concluded that a standard was necessary for two reasons. First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.[1] The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) Planning Coordinators, Balancing Authorities, Resource Planners and Tranmission Planners to obtain the data from a neighboring entity. Replacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes. The SDT concluded that because there is a reliability need for Planning Coordinators and Balancing Authorities to obtain demand data for their own reliability purposes and for data sharing between registered entities, a standard was appropriate.

The recommended option of modifying the existing standards to remove the ambiguity and address the FERC directives solves the issues identified with the first two options. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada. The informal development effort recommended this approach and the standard drafting team has accepted this approach for the development of a consolidated standard.

[1] Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities have the authority to collect the necessary data from all applicable registered entities.

Outstanding FERC Directives

There are 11 outstanding FERC directives from Order 693. Each of the directives was extensively reviewed and discussed in detail by the standard drafting team

In the Paragraph 81 initiative of its March 15, 2012 order accepting a new enforcement mechanism,[2] FERC invited the ERO to identify possible requirements that have little to no effect on reliability that could be removed from the NERC Reliability Standards. The standard drafting team took the information from the FERC order into consideration when it discussed the directives related to the MOD C initiative.

Para 1232

Supported by many commenters, **the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans**. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. **Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.**

Consideration of Directive

With regard to the first directive, the Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Regarding the second directive, a modified definition for Demand-Side Management (DSM) is proposed which includes the language directed by the Commission. The drafting team believes this is an equally effective definition. It now reads:

> **Demand-Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

Consideration of Directive

Weather effects actual demand. Among other things, space conditioning (air conditioning, heat pumps and other heating loads) influences actual demand values significantly. The standard drafting team believes the important consideration in this directive is to be able to adjust the actual demand data to account for weather effects, so a "meaningful comparison with forecast values" can be made. Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now

[2] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3.2.1). Further, Requirement R1 part 1.5.5 also requires that a comparison be made. Each load forecasting entity can decide which aspects of weather need to be measured so as to adjust the actual demand for the difference in demand due to the differences between forecast weather conditions and actual weather conditions (weather normalization). Reporting weather normalized actual demand data instead of the temperature and humidity data also addresses the concerns in the paragraph 1250 directive below. Entities forecasting demand that is not weather sensitive will not be required to provide data that has no impact on their forecast or actual demand data.

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

Requirement R1 part 1.3.2.1 of the proposed standard MOD-031-1 Demand and Energy Data asks for weather normalized data. If the load is not sensitive to weather, then the weather normalized and actual load will be the same.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.5.5).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.5).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

The Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain if certain data is unavailable and why the entity believes the lack of data does not materially impact reliability.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain why the entity believes their forecast method does not materially impact reliability.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

Requirement R1 parts 1.3.5 and 1.4.5 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must report DSM data and provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 parts 1.5.2, 1.5.3 and 1.5.4).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The standard drafting team accepted this consolidation approach and modified the requirements to ensure data will be made available to support assessments of the reliability of the Bulk Electric System.

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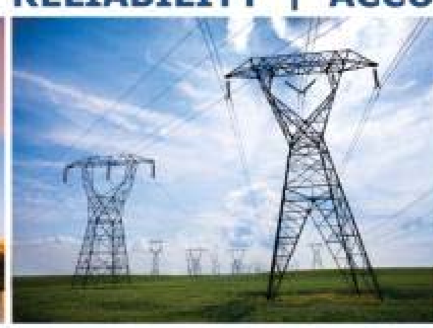
White Paper on the MOD C Standards

MOD-016, MOD-017, MOD-018, MOD-019, and MOD-021

February 14, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

NERC Reliability Standards MOD-016, -017, -018, -019, and -021 (referred to herein as the “MOD C” standards), were approved in the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) Order No. 693. Collectively, the MOD C standards pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events as follows:

- MOD-016-1.1 is the umbrella standard that contains the documentation required for the data collection requirements.
- MOD-017-0.1 provides for the data requirements for actual and forecast peak demand and net energy for load.
- MOD-018-0 provides for the documentation of the treatment of nonmember demand data and how uncertainties are addressed in the forecasts of demand and net energy for load.
- MOD-019-0.1 provides for the collection of interruptible demands and direct control load management.
- MOD-020-0 addresses the need to provide interruptible demands and direct control load management data to System Operators and Reliability Coordinators.
- MOD-021-1 provides for the documentation of how Demand-Side Management demands are accounted for in demand and energy forecasts.

NERC initiated an informal development process to address directives in Order No. 693 to modify certain aspects of the MOD C standards. The first informal meeting was held in February 2013 at NERC’s Washington, D.C. office. Participants were industry subject matter experts (SMEs), NERC staff, and staff from FERC’s Office of Electric Regulation. The small ad hoc group of SMEs participated in discussions about the outstanding FERC directives and possible resolutions to address the directives. The group also discussed the six standards (MOD-016 through MOD-021) and identified issues with the present standards. The group very quickly identified MOD-020 as dealing with the operational time frame and concluded that it should not be addressed with the other standards at this time since they were applicable to the planning horizon.

A pure data reporting standard would be a candidate for retirement under Paragraph 81. During the review of the requirements in the current standards, it was not clear whether every Planning Authority (PA) and Balancing Authority (BA) had authority to collect this data from all registered entities in their PA/BA area. Since the data being collected has a reliability purpose in the development of future reliability assessmentseach PA/BA needs the authority to collect this data. In order to specify the scope and limitations of the data collection authority, there was a consolidation of the remaining five MOD C standards into a single standard. The consolidation effort was supported by the industry as the group conducted informal development outreach. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada.

As detailed below, this document discusses the outstanding directives from FERC Order No. 693 and identifies the applicable requirements in standard MOD-031-1 Demand and Energy Data that address each directive.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of collecting data used in reliability assessments. This document outlines the next generation of these standards and proposes to combine the reliability components of this package of standards into one standard. The remaining requirements in this package would either be retired as administrative or captured as instructional or explanatory in a white paper.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how NERC is addressing each of the outstanding FERC directives assigned to these FERC-approved standards. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

Technical Discussion

The fundamental test for determining the adequacy of the B~~b~~ulk Electric~~power~~ S~~s~~ystem (BE~~P~~S) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions.

The collection of demand projections requires coordination and collaboration between Planning Authorities/Planning Coordinators, Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts—as well as the supporting methods and assumptions used to develop these forecasts—will ultimately enhance the reliability of the BE~~P~~S. Consistent documenting and information-sharing activities will also improve the efficiency of planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and Demand-Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

The ad hoc group identified two options to address MOD-016 through MOD-019 and MOD-021. The first option was to retire the five standards and include the data being collected in the *Long-Term Reliability Assessment* (LTRA). The second option was to combine the five standards into a single standard with three or four clear requirements.

Initially, the ad-hoc group suggested tying the standard to the LTRA. Currently, the majority of LTRA data is required for the completion of the Form EIA-411, administered by the Energy Information Administration (EIA). Accordingly, failure by the Regional Entities to provide this data to NERC on an annual basis is in violation of federal law. In the absence of a standard however, NERC has no ability to directly address an entity that fails to provide requested LTRA data. This especially applies for Canadian provinces that do not provide data for the Form EIA-411.

A second alternative to addressing data requirements in the absence of a standard is the implementation of either a Section 800 or Section 1600 data request. The SDT concluded that a standard was necessary for two reasons. First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.[1] The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.

Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO's reliability assessments; and (2) ~~the sharing of such data between Load Serving Entities, Distribution Providers,~~ Planning Coordinators, Balancing Authorities, Resource Planners and Tranmission Planners to obtain the data from a neighboring entity. Replacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes. The SDT concluded that because there is a reliability need for Planning Coordinators and Balancing Authorities to obtain demand data for their own reliability purposes and for data sharing between registered entities, a standard was appropriate.

The recommended option of modifying the existing standards to remove the ambiguity and address the FERC directives solves the issues identified with the first two options. Creating a single standard provides a means of ensuring data will be collected and shared among the necessary parties (LSEs, BAs, TPs, etc.) in both the United States and Canada. The informal development effort recommended this approach and the standard drafting team has accepted this approach for the development of a consolidated standard.

[1] Because certain Canadian provinces have adopted only select portions of the NERC Rules of Procedure, a standard is necessary to ensure that NERC and the Regional Entities have~~has~~ the authority to collect the necessary data from all applicable registered entities.

Outstanding FERC Directives

There are 11 outstanding FERC directives from Order 693. Each of the directives was extensively reviewed and discussed in detail by the standard drafting team

In the Paragraph 81 initiative of its March 15, 2012 order accepting a new enforcement mechanism,[2] FERC invited the ERO to identify possible requirements that have little to no effect on reliability that could be removed from the NERC Reliability Standards. The standard drafting team took the information from the FERC order into consideration when it discussed the directives related to the MOD C initiative.

Para 1232

Supported by many commenters, **the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans**. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. **Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.**

Consideration of Directive

With regard to the first directive, the Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Regarding the second directive, a modified definition for Demand-Side Management (DSM) is proposed which includes the language directed by the Commission. The drafting team believes this is an equally effective definition. It now reads:

> **Demand-Side Management:** All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Para 1249

The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

Consideration of Directive

Weather effects actual demand. Among other things, space conditioning (air conditioning, heat pumps and other heating loads) influences actual demand values significantly. The standard drafting team believes the important consideration in this directive is to be able to adjust the actual demand data to account for weather effects, so a "meaningful comparison with forecast values" can be made. Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now

[2] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf

requires weather-normalized actual demand data to be reported (Requirement R1 part 1.3.2.1). Further, Requirement R1 part 1.5.5 also requires that a comparison be made. Each load forecasting entity can decide which aspects of weather need to be measured so as to adjust the actual demand for the difference in demand due to the differences between forecast weather conditions and actual weather conditions (weather normalization). Reporting weather normalized actual demand data instead of the temperature and humidity data also addresses the concerns in the paragraph 1250 directive below. Entities forecasting demand that is not weather sensitive will not be required to provide data that has no impact on their forecast or actual demand data.

Para 1250

We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. **We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.**

Consideration of Directive

Requirement R1 part 1.3.2.1 of the proposed standard MOD-031-1 Demand and Energy Data asks for weather normalized data. If the load is not sensitive to weather, then the weather normalized and actual load will be the same.

Para 1251

The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the actual and forecast demand compared (Requirement R1 part 1.5.5).

Para 1252

The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, **we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.**

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.5).

Para 1255

We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

Consideration of Directive

The Transmission Planner has been added to the Applicability Section of the proposed standard MOD-031-1 Demand and Energy Data.

Para 1256

The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. **The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.**

Consideration of Directive

The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain if certain data is unavailable and why the entity believes the lack of data does not materially impact reliability.

Para 1265

Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, **the Commission directs the ERO to address this matter in the Reliability Standards development process.**

Consideration of Directive

The requirements of MOD-018 are now included in MOD-031 Requirements R1.5.1 and R1.5.5 which require explanations of forecast assumptions, comparisons of actual to forecast data and a discussion of how assumptions and forecasts were adjusted. The SDT believes these requirements allow an entity to explain why the entity believes their forecast method does not materially impact reliability.

Para 1276

The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. **Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.** We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1277

We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

Consideration of Directive

Requirement R1 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must provide an explanation of how the assumptions and methods for future forecasts were adjusted (Requirement R1 part 1.5.4).

Para 1298

We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. **Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.**

Consideration of Directive

Requirement R1 parts 1.3.5 and 1.4.5 of the proposed standard MOD-031-1 Demand and Energy Data now states that an entity must report DSM data and provide an explanation of how DSM is forecasted and adjusted for errors (Requirement R1 parts 1.5.2, 1.5.3 and 1.5.4).

Conclusion

In developing the MOD C initiative, the informal ad hoc group and entities that participated in informal development discussed the key reliability impacts of the existing MOD C NERC Reliability Standards. The group identified and discussed issues at varying lengths early in the process and decided to consolidate the existing five standards into one pro forma standard. The standard drafting team accepted this consolidation approach and modified the requirements to ensure data will be made available to support assessments of the reliability of the Bulk Electric~~Power~~ System.

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Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R3	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirements R2 and R4	Requirements R2 and R4 of the standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5.
MOD-017-0.1 R1.1	Requirement R1 part 1.3.1	The standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.3.2	The standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.4.1	The standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.4.2	The standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	Omitted	This is no longer need now that all registered entities within each region is a member of that region.
MOD-018-0 R1.2	Requirement R1 part 1.5.1	The standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirements R2 and R4	The standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.4.3	The standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.5.2	The standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.5.3	The standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The standard will require entities to provide the requested data by a certain date.

Project 2010-04 Mapping Document

Transition of MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1 to MOD-031-1

Standard: MOD-016-1.1 – Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable Demand-Side Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-016-1a R1	Requirement R1	The pro forma standard requires the Planning Coordinator or Balancing Authority to develop and issue a data request as necessary.
MOD-016-1a R1.1	Requirement R1	MOD-010 through MOD-015 does not depend on these standards for their data (they collect the data needed). TPL-005 and TPL-006 are not FERC approved standards but the data is available for their use. The standard will require the Planning Coordinator or Balancing Authority to identify the format for providing data.
MOD-016-1a R2	Requirement R1	See comments on Requirement R1.
MOD-016-1a R2.1	Requirement R1 part 1.2	The standard requires the Planning Coordinator or Balancing Authority to provide a timeline for providing the data.
MOD-016-1a R3	Requirement R1	See comments on Requirement R1.
MOD-016-1a R3.1	Requirement R3~~1~~	The Planning Coordinator or Balancing Authority must respond within the time allotted by the Electric Reliability Organization (ERO) or Regional Entity (RE).

Standard: MOD-017-0.1 – Aggregated Actual and Forecast Demands and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-017-0.1 R1	Requirements R2 and R4	Requirements R2 and R4 of the standard will require entities to provide data as outlined in Requirement R1 parts 1.1 through 1.5.
MOD-017-0.1 R1.1	Requirement R1 part 1.3~~4~~.1	The standard will require entities to provide integrated hourly demands in megawatts (MW) for the prior year.
MOD-017-0.1 R1.2	Requirement R1 part 1.3~~4~~.2	The standard will require entities to provide monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.
MOD-017-0.1 R1.3	Requirement R1 part 1.4~~5~~.1	The standard will require entities to provide monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.
MOD-017-0.1 R1.4	Requirement part R1 part 1.4~~5~~.2	The standard will require entities to provide peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future.

Standard: MOD-018-0 – Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-018-0 R1	Omitted	This requirement serves no direct purpose other than as a bridge to the sub-requirements below.
MOD-018-0 R1.1	~~Requirement R1 part 1.6~~Omitted	This is no longer need now that all registered entities within each region is a member of that region.
MOD-018-0 R1.2	Requirement R1 part 1.5~~7~~.1	The standard will require entities to provide the assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts.
MOD-018-0 R1.3	Requirement R1	This is now a part of the data reporting request developed in Requirement R1.
MOD-018-0 R2	Requirements R2 and R4	The standard will require entities to provide the data requested in Requirement R1 parts 1.1 through 1.5.

Standard: MOD-019-0.1 – Reporting of Interruptible Demands and Direct Control Load Management		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-019-0.1 R1	Requirements R1 part 1.4~~5~~.3	The standard will require entities to provide forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions.

Standard: MOD-021-1 – Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
MOD-021-1 R1	Requirements R1 part 1.5~~7~~.2	The standard will require entities to provide the Demand and energy effects of Interruptible and Direct Control Load Management.
MOD-021-1 R2	Requirements R1 part 1.5~~7~~.3	The standard will require entities to provide how DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load.
MOD-021-1 R3	Requirements R1 part 1.2	The standard will require entities to provide the requested data by a certain date.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

MOD-031-1 – Demand and Energy Data

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						X[3]								
R2	X[4]	X[4]				X[4]								X[4]	
R3	X[5]						X[3,5]								
R4	X					X	X[3]			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.
[4] As identified by a Planning Coordinator or Balancing Authority in a data request issued per Requirement R1 Part 1.1 of MOD-031-1.
[5] As requested by applicable Regional Entity.

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 or Balancing Authority may develop and issue a data request, as necessary, for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data from applicable entities in their area.[6] The data request shall include:

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30-days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Total Internal Demands in megawatts for the prior year.

1.3.2. Monthly and annual peak hour actual Total Internal Demands in megawatts for the prior year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior year.

1.3.4. Annual peak hour weather normalized actual Total Internal Demand in megawatts for the prior year.

1.3.5. Monthly and annual peak hour deployed and realized Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator in megawatts for the prior year.

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Forecasts of Interruptible Load and Direct Control Load Management under the control or supervision of the System Operator for up to ten calendar years into the future, as requested, for summer and winter peak system conditions.

1.5. A request to provide a summary explanation of the following, if necessary:

1.5.1. The assumptions and methods used in the development of aggregated peak Demand and Net Energy for Load forecasts.

[6] For the Balancing Authority, "their area" encompasses their Balancing Authority Area as defined in the NERC Glossary of Terms. For the Planning Coordinator, "their area" encompasses the facilities for which the Planning Coordinator coordinates and integrates transmission facilities, service plans, resource plans, and protection systems.

1.5.2. The Demand and energy effects of Interruptible and Direct Control Load Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the peak load forecast compares to actual load for the prior calendar year with due regard to controllable load,[7] temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with 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[8]:

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.
Copies of entity's data requests developed and issued in accordance with Requirement R1, or a statement that no data requests were issued.

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.

[7] For the purpose of this standard, the term "controllable load" means both Interruptible Load and Direct Control Load Management as referenced in FERC Order 693 Paragraph 1267.

[8] 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.

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.
	For data requests selected by auditor for audit testing, review and verify the request included items described in parts 1.1 and 1.2.

Note to Auditor: Items listed in parts 1.3 through 1.5.4 are optional and are included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard.

Entity assertions that no data requests were issued (see "a statement that no data requests were issued" in the Evidence Requested section above) do not have to be in writing.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Applicable Entity shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1.

M2. Each Applicable Entity shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R2.

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[9]:

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 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 responses to Planning Coordinator or Balancing Authority's data request(s) were made in accordance with Requirement R1 and within timetable established in part 1.2.

Note to Auditor: Based on the language in the requirement and the purpose of the standard, which is to facilitate the sharing of data to support reliability studies, the auditor should not only verify that the data was delivered within the timeframe(s) specified, but also verify that the data delivered met the requirements of the request. However, this standard does not specify criteria around quality of the data, so auditors should not make any assessments in that regard. The responding entity does not have to provide data beyond that requested per parts 1.3 through 1.5.4 of Requirement R1.

[9] 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.

Auditors at their discretion may communicate with Planning Coordinators or Balancing Authorities to determine if data requests made of entity under audit were delivered within the timeframe(s) specified and met the requirements of the request.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity upon request. In no event, however, shall the Planning Coordinator or the Balancing Authority be required to provide the data in less than 75 days from the date it received the data request from the Regional Entity.

M3. Each entity identified by the Regional Entity in its data request, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested in accordance with Requirement R3.

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[10]:

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 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

[10] 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.

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, 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.
	Review evidence (documented date of the Regional Entity's request and entity's reply) to determine if they provided responses to Regional Entity's data request(s) in accordance with Requirement R3 and within 75 days from the receipt date of the data request.

Note to Auditor: Auditor should communicate with entity's Regional Entity to determine whether the Regional Entity had made a data request to the entity under audit. In the instance where the Planning Coordinator or the Balancing Authority collected additional data from Applicable Entities, the additional information may be provided to the Regional Entity but there is no obligation to do so under this requirement.

Auditor Notes:

<u>R4 Supporting Evidence and Documentation</u>

R4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner shall, within 45 days of a written request for the data included in parts 1.3-1.5 of Requirement R1 from any other Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated reliability need for such data, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity is not required to:

- provide any data not within the scope of part 1.3-1.5 of Requirement R1;
- alter the format in which it maintains or uses the data; or

- provide data that conflicts with the Applicable Entity's confidentiality, regulatory, or security requirements.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Load Serving Entity, Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner identified in Requirement R4, shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

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[11]:

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 listed in M4 as well as a copy of the data request; or a statement that a data request was not received.

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.

[11] 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.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to MOD-033-1, 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.
	Review evidence (documented date of request and reply) to determine if entity responses to data request(s) were made in accordance with Requirement R4 and within 45 days of the date of the written request.

Note to Auditor: Based on the language in the requirement and the purpose of the standard, which is to facilitate the sharing of data to support reliability studies, the auditor should not only verify that the data was delivered within the timeframe(s) specified, but also verify that the data delivered met the requirements of the request. However, this standard does not specify criteria around quality of the data, so auditors should not make any assessments in that regard. The responding entity does not have to provide data beyond that requested per parts 1.3 through 1.5.4 of Requirement R1.

Auditors, at their discretion, may communicate with the requesting Load Serving Entities, Planning Coordinators, Balancing Authorities, Transmission Planners, Resource Planners to determine if responses to data requests were appropriate in accordance with this Requirement.

Entity assertions that no data requests were issued (see "a statement that no data requests were issued" in the Evidence Requested section above) do not have to be in writing.

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/05/2013	NERC compliance, Standards	New Document

Violation Risk Factor and Violation Severity Level Justifications

MOD-031-1 – Demand and Energy Data

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-031-1 – Demand and Energy Data. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, 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 of a medium risk requirement 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.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, 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.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification – MOD-031-1 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R1 prescribes data that may be collected for analysis. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R1 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to collect data.

VSL Justification – MOD-031-1 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The Requirement is binary and therefore has one VSL.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and therefore has on VSL, severe. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3:	The proposed VSL is consistent with the corresponding requirement.

Violation Severity Level Assignment Should Be 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 proposed VSL is not based on a cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R2 ensures that once data is collected, it is passed on to the appropriate entity. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard:

	All of the parts within Requirement R2 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2:	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2a: The proposed VSL is not binary Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently 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 proposed VSL is not based on cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R3 ensures that once data is collected, it is passed on to the appropriate entity. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R3 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL is worded consistently with the corresponding requirement.

Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – MOD-031-1 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	Consistent with NERC's VRF Guidelines. A VRF of medium is consistent with the NERC VRF definition. Requirement R4 ensures that neighboring entities have the ability to collect data. Additionally, the Medium VRF is consistent with the prior versions of this Requirement in the currently effective version of the standard.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: It is difficult to argue that a failure to collect the data will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R4 are consistent with one another and considered a medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of this Requirement in the currently effective version of the

	standard.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition. A violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This Requirement has one objective – to ensure that data is collected.

VSL Justification – MOD-031-1 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary

Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently 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 proposed VSL is not based on cumulative number of violations.

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Final Ballot Now Open through May 5, 2014

Now Available

A final ballot for **MOD-031-1 – Demand and Energy Data** is open through **8 p.m. Eastern on Monday, May 5, 2014.**

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

Instructions for Balloting

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, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate 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.

Standards Announcement

Project 2010-04 Demand Data (MOD C)
MOD-031-1

Final Ballot Results

[Now Available]

A final ballot for **MOD-031-1** concluded at **8 p.m. Eastern on Monday, May 5, 2014.**

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Standard	Quorum / Approval
MOD-031-1	80.37% / 90.00%

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 the appropriate 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 (via email), 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 2010-04 MOD-031-1 (MOD C)
Ballot Period:	4/25/2014 - 5/5/2014
Ballot Type:	Final
Total # Votes:	303
Total Ballot Pool:	377
Quorum:	**80.37 % The Quorum has been reached**
Weighted Segment Vote:	90.00 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

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	102	1	63	0.863	10	0.137	0	9	20
2 - Segment 2	9	0.8	8	0.8	0	0	0	1	0
3 - Segment 3	85	1	50	0.893	6	0.107	0	8	21
4 - Segment 4	29	1	21	0.875	3	0.125	0	0	5
5 - Segment 5	87	1	45	0.833	9	0.167	0	14	19
6 - Segment 6	50	1	33	0.846	6	0.154	0	6	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	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	0	2
Totals	**377**	**6.9**	**231**	**6.21**	**34**	**0.69**	**0**	**38**	**74**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
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	Affirmative	
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
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	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
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		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
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	
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	Affirmative	Supports comments by SPP - Robert Rhodes
1	Lakeland Electric	Larry E Watt	Negative	
1	Lee County Electric Cooperative	John Chin		
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	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
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	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	supports the comments of Thomas Foltz - American Electric Power
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	PacifiCorp	Ryan Millard		
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		
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	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
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
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
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	Abstain	
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	Abstain	
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	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
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	Abstain	
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	Abstain	
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		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Affirmative	
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		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	East Kentucky Power Coop.	Patrick Woods	Negative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	Supports PJMs comments
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell		
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	Supports comments by SPP - Robert Rhodes
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		
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	Mississippi Power	Jeff Franklin		

3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
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		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
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	Affirmative	
3	PacifiCorp	Dan Zollner		
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	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	Affirmative	
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		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	NO COMMENT RECEIVED
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
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	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
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	Affirmative	COMMENT RECEIVED
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer		
4	Public Utility District No. 1 of Snohomish	John D Martinsen	Affirmative	

	County			
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
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
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
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	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
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		
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
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	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	
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	Affirmative	
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		
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	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	

5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
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	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
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	Abstain	
5	PacifiCorp	Bonnie Marino-Blair		
5	Portland General Electric Co.	Matt E. Jastram		
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	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Abstain	
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	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	Abstain	
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	Affirmative	
5	WPPI Energy	Steven Leovy		
5	Xcel Energy, Inc.	Liam Noailles	Abstain	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
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	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		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
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	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
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	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
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	Affirmative	
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	Abstain	
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		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy		
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		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit G

Standards Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2010-04 (MOD C) Standards Drafting Team

	Name	Company	Functions	Region(s)
1	Mark Kuras*	PJM	BA, TOP, TO, TP, RP	RFC, SERC, NPCC
2	Josh Collins*	Midcontinent Independent System Operator (MISO)	BA, PC, TP, RC, LSE, Large Electricity End Users and Market Operator	MRO, RFC, SERC
3	Paul Kure*	Reliability*First* Corporation (RFC)	RC, PC	RFC, SERC, MRO, NPCC
4	Brian Glover	Great River Energy	LSE, PC, TSP, TO, and Electricity Generators	MRO
5	Robert Emmert	Califiornia ISO (CAISO)	PC, RTO and ISO	WECC
6	Barbara Doland	SERC Reliability Corporation, Inc.	RC, PC	SERC
7	Andrey Oks	Northeast Power Coordinating Council, Inc. (NPCC)	RC, PC	NPCC, RFC, MRO