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.