

under BAL-003-1. (3) Some BAs may elect to procure a portion of its FRO through bilateral agreements for certain hours (e.g. off-peak) with a neighboring BA. Since a contingency could be in a BA other than the two BAs under a bilateral agreement, the standard or background document needs to clarify the duration of frequency response so that transmission reservation is not a requirement for frequency response. The ISO believes that the BA experiencing the contingency should have adequate arrangements in place to deal with internal contingencies.

Group

Northeast Power Coordinating Council

Guy Zito

Northeast Power Coordinating Council

Yes

Yes

No

If a BA is using a frequency bias setting and is not providing Overlap Regulation Service (supplying actual interchange, frequency response, and schedules to another BA), then it can be assumed that the BA is supplying regulation service. Was the intent of the requirement to simply state that all BA's must have a bias setting less than zero at all times? The intent of this requirement needs to be clarified.

No

This document lacks definitions of terms such as CCadj, DFcc, DFcbr, resource contingency criteria (in the attachment, this is called the "target contingency criteria"), etc. A sample calculation would be of value to entities. "The largest category C (N-2) event is used for all interconnections except the Eastern which uses the largest event in the last 10 years". All interconnections should be using the same design basis contingency. The NERC 2012 CPS2 bounds has an Eastern Interconnection frequency bias of -6,360 MW/.1Hz. Why does this attachment refer to an Interconnection frequency response obligation of -1,002MW/.1Hz.? This is a significant difference.

No

While the discussion of primary frequency response includes inertial energy, the term inertial energy is missing from the definition of "primary frequency response".

No

The purpose of BAL-003 was to calculate frequency bias in the ACE equation used in BAL-001. The Standard is currently confusing to understand, and it is unclear how the bias is calculated. It is recommended that efforts should be made to clarify the changes, especially in Attachment A.

The VSL's refer to the FRM (Frequency Response Measure). If that is the intent of the Standard, then GO's and GOP's should be included in the applicability since they are the entities responding to the AGC signals. If the intent is the FRO (Frequency Response Obligation) only, then the VSL's should be updated.

Individual

Howard F. Illian

Energy Mark, Inc.

Yes

Yes

Yes

Yes
Yes
Yes
Yes
Yes
Although I am in favor of using linear regression to determine the FRM, the standard using Median is better than not having a standard.
Group
Edison Electric Institute
Mark Gray
Edison Electric Institute (Trade Association)
Yes
No
EI does not fully agree with the definition of a "Frequency Response Sharing Group" (FRSG). In the definition offered in the new Standard, it states that the FRSG "collectively maintain, allocate, and supply operating resources". Of the three roles, a balancing authority only maintains load-interchange-generation balance through the allocation of resources. Therefore, EI suggests that the definition be changed to more appropriately align with the role of a BA, which we believe would be to allocate resources in a manner that effectively allows the sharing of resources necessary to achieve a FRO within the defined sharing group, which might otherwise not be possible or practical by a BA on its own.
Yes
Yes
Yes
EI supports the ERO's role as defined in the procedure but is concerned that the procedure, unlike approved NERC standards, is unbounded by the current rules for developing standards. For that reason, EI recommends that the procedure become more formalized and integrated into the standard as an addendum thereby avoiding any Industry concerns that future modification might occur outside the approved processes
Yes
EI finds the method to be acceptable but as mentioned in our response to question No. 5 (above), we believe that the procedure should be more formally documented as an addendum. Such a change would ensure that the document would remain unchanged outside of the approved standards making process. Additionally, EI does not support using 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the results is an allocation which we believe is acceptable. In the future, should the SDT decide to use 59.7 Hz as the basis for the FRO, than it will need to follow a methodology similar to the other interconnections for determining the credible multiple contingency to cover.
Yes
Yes

EEI supports the efforts and improvements made by the Standards Drafting Team (SDT) in the latest version of BAL-003 and believe those changes have been responsive to the directives in Order 693. However, we recognizes that the Industry has struggled with this standard and remains split as to how best to respond to those directives and in some cases there are those who question whether a standard is even necessary. Given the many open issues and the concerns expressed by stakeholders we anticipate that this standard will once again fail to achieve sufficient support to gain approval. Should the Standard fail to achieve ballet approval, it is our hope that NERC Staff and the NERC Board of Trustees will allow the SDT a little more time to resolve any final issues that have been identified in this latest ballet. Although we recognize that May 31, 2013 does not leave the ERO with a lot of time to comply with this FERC imposed deadline, we still remain confident that given the progress made by the SDT a standard, which is acceptable to the Industry, is still possible. To the extent EEI can help, we are committed to working with member companies to communicate the issues and exchange insights from the SDT to help as we can to achieve a positive outcome.

Individual

Thad Ness

American Electric Power

As provided in question 2 below, AEP does not agree with the definition containing the Frequency Response Sharing Group as this function does not exist at this point in time.

No

AEP does not necessarily disagree with the words of the definition. However, AEP does not believe it is appropriate to define a new function that is not in the NERC Rules of Procedure, NERC Statement of Registry Criteria, or the NERC Functional Model. It is premature to incorporate this entity without a proposed change to these governing NERC documents.

No

AEP believes this question in the comment form is incorrect. It appears that R3 and R4 are inadvertently merged together.

No

AEP is under the impression that there are some requirements, which though not explicitly stated, are implied in Attachment A. AEP feels strongly that these "sub-requirements" should be clarified and contained within the body of the requirements of the standard.

There is no leverage for the BA to require the generator to carry their burden of addressing governor settings or droop settings, yet the BA is obligated to meet some performance measures in that regard. This revision adds new performance measure responsibilities on the BA who likely has no direct control over every resource affecting their performance within their footprint. We are not necessarily challenging the performance measures themselves, nor their underlying objectives, however AEP views this as a gap in responsibilities which potentially effects reliability. AEP suggests that GOPs be considered as part of this standard so that their performance can be factored into the process to meet the performance objectives.

Group

NREL Transmission and Grid Integration Group

Erik Ela

National Renewable Energy Laboratory

Yes

Yes

Yes

UI believes the VRF should be High. The VRF justification for Medium is that the prior year's bias setting would exist in the control system so the impact would not cause a Cascade. UI thinks that is an adjustment factor that is applied after non-compliance is determined. Not having settings is likely to cause cascade so the VRF is High.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Arizona Public Service Company
Yes
Yes
No
The supporting document on the standards page does not provide information on CB Ratio and why it is used. It significantly increases FRO and should be justified based upon strong technical basis and actual experience. (Please also see AZPS response to question 6, The Frequency Response Initiative Report should be on the Standards page).
NO: 1. The Frequency Response initiative report should be added to the standard as an appendix. It is not clear where to find this report. 2. The justification for dividing delta frequency with C to B ratio is not adequate and not clear.
NO: 1. Either do not use C to B Ratio or provide adequate rationale for using it. It appears to make FRO unnecessarily too conservative and is not justified based upon experience. 2. The VRF is too complicated and hard to understand. It must be either simplified or should be followed by example. 3. The Frequency Response Obligation Methodology on Page 7 of "Procedure" does not show any formula (it is blank).
As mentioned in Item 8 above, the VRF language is too complicated and hard to follow. Even though the VRF poll is non binding, it needs to be clear and simple enough to be understood.
Individual
Travis Metcalfe
Tacoma Power
Yes
Yes
Yes
Yes
The addition to the Frequency Bias Setting definition of "and discourage response withdrawal through secondary control systems" seems incomplete. Tacoma Power does not see anything in the standard

that addresses (or measures) how a frequency bias setting will discourage response withdrawal through secondary systems. This should either be more fully addressed or removed.
Individual
Nazra Gladu
Manitoba Hydro
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
(1) Page 2, Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting: States that the ERO is responsible for “annually assigning an FRO and Frequency Bias Setting to each BA.” No mention is made of FRSGs. (2) Neither R1 nor the referenced Attachment A clarifies the FRM requirements for an FRSG to comply versus a BA. In particular, compared to BAL-002-0 R1.1, which clearly states that the BA may elect to fulfill its obligation through an FRSG and that in such cases the FRSG has the same responsibilities as each BA (that is a participant in the FRSG). (3) Attachment A refers to an FRSG calculating FRM, but the standard does not.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Purpose: Is the reference to ‘Interconnection Frequency’ supposed to be ‘Frequency Response’? This would be consistent with later wording in the standard. R1: (1) The acronym ‘FRO’ is used inconsistently within the document. (2) The phrase “to ensure that sufficient Frequency Response ...” should be separated from the requirement as it is (i) not descriptive of the required actions; (ii) redundant with the stated purpose at the beginning of the standard. In general, such a drafting technique should be avoided as it may allow Responsible Entities to argue that a violation has not occurred where the specific action that is described has not been taken, but the purpose referenced in the requirement has been met. M1: The reference to ‘documented formula’ is not clear. Does this imply that the FRSG or BA have a record of their calculation? In addition, there is a typo, a random ‘)’ after FRM. M2: Should include the words ‘and uses a fixed Frequency Bias Setting...’ after overlap Regulation Service to make the wording consistent within the Requirement. M3: The wording of this measure switches tenses between ‘is’ and ‘was’. For consistency, we suggest that this be corrected. NERC Glossary definition of an FRSG is a group of BAs that collectively maintain, allocate and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an FRSG if the RSG Agreement allows for such delegation. Data Retention 1.3.: (1) As the standard is currently drafted, both the BA and the FRSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records. (2) In the third paragraph, it should be clarified who is required to keep information related to non compliance if the BA belongs to an FRSG – the BA or the FRSG or both.
Individual
Alice Ireland
Xcel Energy

Yes
Yes
Yes
It is not clear however, as to if this is actually part of the standard or if it is a document that can be revised without going through the standards development process. Also, the formatting of the document should be modified to clearly identify where 'steps/actions' are needed from responsible parties, whether that be the ERO or BA/FRSG.
YES. It is not clear however, as to if this is actually part of the standard or if it is a document that can be revised without going through the standards development process. Also, the formatting of the document should be modified to clearly identify where 'steps/actions' are needed from responsible parties, whether that be the ERO or BA/FRSG.
Xcel Energy supports this proposed revision to the standard as a first step and suggests that after operating for a couple of years under the revised standard, that NERC initiates a more complete study to support any modifications to the standard.
Group
MRO NSRF
WILL SMITH
MIDWEST RELIABILITY ORGANIZATION
Yes
Yes
No
The MRO NSRF is concerned with the drafting team's exclusion of single Balancing Authority Interconnections from compliance with Requirement R3. To ensure a consistent approach in the application of the standard, recommend R3 be revised as follows: (R3). Each Balancing Authority that is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: ...
Yes
MRO NSRF AGREES
MRO NSRF AGREES
MRO NSRF AGREES
The MRO NSRF is concerned with the drafting team's exclusion of single Balancing Authority Interconnections from compliance with Requirement R2. To ensure a consistent approach in the application of BAL-003-1, recommend R2 be revised as follows: (R2). Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation ...
Group
pacificorp

ryan millard
pacificorp
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
Yes
Yes
Yes
BPA is responding to 3.1 and 3.2 of R3. The bullets listed in question 3 on the original comment form appear to be for Requirement R4. BPA is in support of R3.1 and R3.2.
No
BPA does not agree with the methodology in Attachment A. Please see BPA's response to question 6 as well as BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf .
No
BPA does not agree with the methodologies outlined in Attachment B. Please see BPA's response to question 6 as well as BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf
No
BPA does not have specific changes to the methodology to suggest, however, a methodology that arrives at a negative 840 MW per tenth Hz for WECC is obviously under-calculating the frequency bias obligation. Currently WECC has an interconnection bias of over 2000 MW / 0.1Hz and with this bias the frequency is steady state following point B on the frequency response curve. BPA would expect to see frequency decline after point B if the FBO is lowered by almost 60%. BPA also must reiterate that there is still a problem with the method used for modifying the FBO and frequency bias for Balancing Authorities. A high-performing Balancing Authority will have its frequency bias increased each year due to higher response during the events chosen by the ERO. Conversely, a low-performing Balancing Authority will have its frequency bias reduced each year due to lower response during the events

chosen by the ERO.
No
BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf .
No
BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf .
Individual
Shammara Hasty
Southern Company (Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Services, Inc., Southern Company Generation, Southern Company Energy Market)
Yes
Yes
Yes
Yes
Yes
No
Attachment A states that Form 1 is posted annually. The ERO support document selects events annually. The timing for the two documents needs to be aligned so that the set of selected events does not change from quarter to quarter. (If three events are selected for the first quarter those same events will be a sub-set of the 20 events selected for the annual compliance calculations.)
No
The industry needs some assurance that the calculation of the Interconnection FRO described in the report cannot be changed outside of the Standards Process for approval by the industry. We do not support using a 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the result is an allocation which can be supported. To the extent that the standard drafting team moves in the direction of using 59.7 Hz as the basis for the FRO, then it needs to follow a methodology similar to the other Interconnections for determining the credible multiple contingency to cover.
Yes
Yes
Please refer to comments for question 9.
The organization selecting events must ensure that the change in frequency is outside the normal dead-band of generator governors. Many of the events selected in the past have not been outside the dead-band and therefore, the frequency response was much less than expected. Southern Company proposes .07 which is consistent with WECC.
Individual
Greg Travis
Idaho Power Company
Yes

BAL-012-1 so that potential double counting (and whether that is proper or improper), is addressed. 3. Project 2007-12's "Frequency Response Standard Background Document" dated October, 2012 lists several methods of obtaining Frequency Response. Most of those are extracted below. We have provided questions and commentary that we ask the team to address. a. "Regulation services." This is addressed in BAL-001-0.1a. The purpose of this standard is "To maintain Interconnection STEADY-STATE FREQUENCY within defined limits by balancing real power demand and supply in real-time. How is this related to Frequency Response for a disturbance? (The team may answer this as part of 2.b above.) b. "Through a tariff (e.g. Frequency Response and regulation service). " The team is advised to review the actual pro-forma OATT schedule for Schedule 3 "Regulation and Frequency Response Service" which is specifically limited to services providers that are "capable of providing this service as necessary to follow the moment-by-moment changes in load." Again, how is this related to Frequency Response for a disturbance? (The team may answer this as part of 2.b above.) c. "From generators through an interconnection agreement." The FERC's pro-forma Standard Large Generator Interconnection Agreement (LGIA) per Order 2003 contains no requirement for generators to provide Frequency Response service, and we are not aware on ANY interconnection agreement that does. We ask that the team point to ANY interconnection agreement with such a requirement. Modification of an interconnection agreement to incorporate such a requirement would require the consent of both parties. d. "Contract with an internal resource or loads." Since Frequency Response service would likely be considered as a necessary service to provide Transmission Service under an OATT, it would require a tariff. What existing tariff applies in the U.S.? The "methods" above that the team has listed have the factual errors described. The standard BAL-003-1 cannot be implemented until the necessary tariffs are developed that permit BAs and FRSGs to contract for Frequency Response services. Once that is done, BAL-003-1 can dictate the performance requirements of a BA or FRSG. • For context, FERC OATT schedules relevant to Frequency Response DO NOT set performance requirements. Schedule 3 (Regulation and Frequency Response Service) sets forth a tariff for the service, while BAL-001-0.1a sets forth performance requirements in aggregate for a BA or RSG. Likewise, Schedule 5 (Operating Reserve - Spinning Reserve Service) and Schedule 6 (Operating Reserve - Supplemental Reserve Service) set tariffs for both services, while BAL-002-1 sets performance requirement. Without an OATT schedule for Frequency Response service, BAs and FRSGs will have no means to contract with generators or loads to provide Frequency Response per BAL-003-1. The team should address this concern.

Individual

Michael Falvo

Independent Electricity System Operator

Yes

Not Applicable

Not Applicable

No

As indicated in our previous comments, the status of Attachment A is unclear. It is a mixture of requirements, criteria, process and guideline. Making a direct reference in the standard's requirements (R1 and R2) makes Attachment A as part of the requirement and hence is enforceable, but it contains process and guideline information that is not subject to assessment. On the other hand, the absence of a Measure to assess adherence to the criteria and process suggests that Attachment A is not enforceable. It is this ambiguity that makes it difficult for the industry to assess the extent to which they must follow the process. Again, we urge the SDT to keep only the criteria/process parts that must be adhered to in Attachment A, and extract the remaining parts and place them in a guideline document, or an appendix. In addition, the Responsible Entities are required to submit Form 1 and Form 2, but such requirements are not written explicitly as "shall", and are imbedded in the Attachment whose mandatory status is unclear. This makes the standard very confusing from an Responsible Entity's obligation and compliance perspective.

Yes

Yes
No
<p>a. We do not support R2 as drafted, specifically the phrase “until directed to change by the ERO”. We do not agree that the ERO has any authority to “direct” a BA or FRSG, or any responsible entities, to make changes to the Frequency Bias Setting or take any operating or operations planning actions. We suggest to replace the word “directed” with “requested”. b. In R2, the words “subject to” can be interpreted differently. We suggest to replace them with “in accordance with” to parallel the intent as conveyed in R1. c. We are still concerned with the status of Attachment A, as indicated in our comments submitted under Q4 – that it is unclear if the materials in Attachment A must be adhered to or not. A standard should not have an attachment whose enforcement status is unclear as part of a requirement. d. FRS Forms 1 and 2 are referenced in Attachment 1, which itself has an unclear status on measurability and enforceability. It is also unclear if FRS Forms 1 and 2 must be used to submit the requested data. Collectively, Attachment 1, FRS Form 1 and Form 2 make the standard very confusing as to which parts must be complied with. Much better clarity is needed to clearly convey the standard’s requirements that are measurable, enforceable and must be complied with.</p>
<p>The proposed effective date for this standard conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of Section A1.3 and A1.4, after “months after applicable regulatory approval”, of the standard to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” The same change should be made to the two bullets in the proposed Implementation Plan.</p>
Individual
Brian J Murphy
NextEra Energy
Yes
<p>NextEra Energy does not support the changes made. It is concerned that certain changes were made to help some large East coast entities that could not comply at the expense of the FRCC region. Specifically, now on page 3 of Attachment A 4th paragraph from the bottom the statement is made “ sets its frequency bias to the greater of”. We believe that this must be changed to either Statement 1 “ Any number the BA chooses between 100% etc” Or Statement 2 “ Interconnection minimum as determined by the ERO” Without this change, NextEra believes the FRCC will be unfairly treated relative to others on the Eastern Interconnection. The technical reasons for this concern was explained during the Standard Drafting Team meetings. In addition, the ERO limit which is set at 0.9% of load should be changed to read within 0.8 or 0.9% of peak load based on the BA’s choice. Also, see page 7 of the Procedure document and compare to page 1 of Attachment A. The formulae abbreviations for the variables in the Procedure are not likewise abbreviated in Attachment A. For example, “Credit for LR” on Attachment A is “CLR” in the Procedure, but it requires cross checking each document to figure this out. Or CBr in Attachment A, Table 1 is represented as DFCBR in the Procedure, Page 7. Since the same variables are being described, these should be represented the same way in both documents throughout. 2. Similarly, is “IFRO” in Table 1 of Attachment A the same as “FROInt” of the equation that follows on page 2? The same abbreviation should be used to represent this variable. The documents should be revised in general along these lines for all terms. 3. In Procedure document, page 5, paragraph 3 it should read “Table 2”, not “1”. 4. In the Procedure, it would be good to show Table 1 and Table 2 as Table 1 of Attachment A (i.e. use table lines and borders). 5. At least in the first usage, ERO in the Procedure document should be spelled out as “Electric Reliability Organization (ERO)”. 6. In Table 1 of Attachment A, the two footnotes preceded by asterisks (single and double on page 2) should be connected to the table by adding a single superscripted asterisk to the Eastern UFLS value of 59.5, and a double superscripted asterisk to the ERCOT LR value of 1,400.</p>

Individual
Don Jones
Texas Reliability Entity
Yes
Yes
Yes
It appears that R3.2 is based on the assumption that governor dead-band settings are 0.036 Hz for all interconnections with multiple BAs. While the ERCOT region has a standard 0.036 Hz dead-band specified in the ERCOT Protocols and Operating Guides, we are not sure if this is applicable to the other regions.
Yes
1. The calculation for the FRO for ERCOT includes a credit of 1400 MW for load resources. 1400 MW is currently the maximum amount of LR that can be procured through the ERCOT ancillary service process. There can be periods during the day where 1400 MW was not procured or is not available (It was noted during the summer of 2012 that on some days, only 900 MW of LR was available through the ancillary service process). Should the calculated IFRO (-286 MW per 0.1 Hz) be modified to account for this variation? 2. Background Document says: "Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation: • Largest category C loss-of-resource (N-2) event • Largest total generating plant with common voltage switchyard • Largest loss of generation in the interconnection in the last 10 years" For ERCOT, the largest loss of generation in the last 10 years was over 3400 MW, and does not match the 2750 MW (N-2) value used for the IFRO calculation.
Yes
1. Event Selection Criteria Item 2: Should certain events require mandatory inclusion for FRM calculation (i.e. DCS events)? 2. Event Selection Criteria Item 6: We disagree with the way this is worded. If a unit trips during this time, as it often can, measured frequency response needs to occur. We understand that the results are impacted by the grid condition and perhaps that is why the SDT decided to exclude the issue. Need to define what is intended by a "large" interchange ramp schedule or load change. May also want to consider changing the language from "will be excluded from consideration" to "MAY be excluded from consideration".
Yes
Yes
Group
MEAG Power
Scott Miller
MEAG Powqer
Agree
Southern Company Services, Inc - Gen
Group

PPL NERC Registered Affiliates
Brent Ingebrigtsen
LG&E and KU Services
No
The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question.
Yes
PPL Affiliates suggest additional detail be added to the definition to ensure the members of the FRSG are all within the same interconnection. The following definition includes the suggested changes: A group whose members consist of two or more Balancing Authorities all within a single interconnection that collectively operate resources required to jointly meet the sum of the Frequency Response Obligations of its members.
No
The NERC posting did not include a redline to Attachment A, therefore, it is not clear what modifications were made. However, there are several modifications that would add clarity to the attachment. The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question, additionally, the following issues should be addressed: In Attachment A, page 3 and elsewhere, clarify that temporary or small transfers of load or generation between BAs do not require notification to the ERO or changes to the FBS or CPS limits. In Attachment A, page 4, a BA should be allowed to be exempt from evaluation any single frequency event where non-conforming load performs contrary to the performance of conventional load (ie. during a frequency decline, the non-conforming load simultaneously increases significantly). By nature, non-conforming load is totally unpredictable, changes quickly, and fluctuates widely. Other than interruption, the BA has no control over the actions of such loads nor can the BA predict or assume any "normal" action by a non-conforming load during a frequency disturbance event. Setting a limit on the number of events that a BA could exempt (regardless of the reason) from FR evaluation in any given year would be more fair and effective in evaluating a BA's frequency response performance.
No
The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question
Yes
The PPL Affiliates applaud the SDT for developing this technical justification document.
No
The PPL Affiliates are concerned that the document referred to "Attachment A" is directly referenced in the proposed standard's requirements but not actually attached to the standard itself as Attachment A. Therefore, it is not clear how the proposed document could be modified in the future. Having such material incorporated into a standard takes away from the open and transparent stakeholder drive process.
Group
PJM Interconnection, LLC
Stephanie Monzon
PJM Interconnection
Yes
Yes
No
With what periodicity does a BA's frequency bias setting have to change to be considered variable bias? For example, if a BA changes it's frequency bias setting monthly based on a percentage of each

month's forecast or historic load, is this considered variable bias subject to compliance with R3 in lieu of R4?

No

The target contingency protection criterion for the Eastern Interconnection is the largest event in the last 10 years (believed to be a 2007 event) which is inconsistent with the other Interconnections. Is periodic review required for this criteria? Will this criteria be revised after the referenced event is older than 10 years? Are the other three interconnection's target contingency protection criteria subject to revision if they experience an event larger than a category C? This BA believes that future periodic analysis should be defined and subsequent findings used to support changes via the standard revision process. What are the procedural requirements for revising Attachment A? This BA is concerned that the procedure for revising Attachment A is undefined and that, for example, the IFRO could be increased absent the formal standard revision process, increasing a BA's FRO and subsequently increasing a BA's compliance risk without providing BA's the opportunity to review, comment, and ballot. Related to the previous comment/question, how often are the statistically derived values in Table 1 subject to a required update? For example, the Eastern Interconnection is adjusted due to observed primary frequency response withdrawal ('lazy L' characteristic). The other Interconnections are adjusted for observed differences between point C and point B. As the frequency response characteristics of any Interconnection change, is Table 1 subject to required analysis and revision? This BA believes that future periodic analysis should be defined and subsequent findings used to support changes via the standard revision process. Attachment A indicates that a BA may exclude an event from annual Form 1 FRM evaluation only if its tie-line or frequency data is corrupt or unavailable. This exempts numerous scenarios that could result in a poor response score due to system variations. These could include, but are not limited to, changing energy schedules, changes in load, and AGC driving units up or down due to the ACE value at the time of the frequency event. This subjects the BA to undue compliance risk even though the BA may have adequate frequency responsive resources at the time. This BA suggests that the FRSDT adopt language (and Form 2 functionality) that allows the exclusion of events that are skewed by these types of situations. Attachment A and Forms 1 & 2 specify that 20 to 52 seconds will be used as the post-event B point average for FRM determination. The number of fast responding resources will increase as the technology for batteries, flywheels, and frequency controlled demand side devices moves forward over time. The 20 to 52 second interval does not adequately incentivize the development of these technologies.

No

The Procedure indicates that events that occur when 'large interchange schedule ramping or load change is happening' and 'events occurring within 5 minutes of the top of the hour' should be excluded from consideration. Since interchange schedule ramping and load change occurs at the BA level, this BA believes that the Procedure allows for the selection of events that occur when a BA is experiencing these conditions but Attachment A does not allow for exemption of these events. Also, the Procedure specifies that events that occur at the top of the hour be excluded, if other qualifying events exist, but this does not take into consideration energy markets that allow for sub-hourly schedule changes (e.g. 15 minutes) and the BA is not permitted to exempt these events on Form 1 subjecting the BA to undue compliance risks.

Yes

Yes

Yes

Yes

No

See previous comments. Also, this standard should be applicable to GOP's as well as BA's with, at a minimum, the following requirements added: Each GOP shall follow all directives of it's Balancing Authority pertaining to frequency responsive operation, including but not limited to the status, droop & deadband settings of their governors. Each GOP shall provide to their BA the status and droop & deadband settings of their governors, and headroom available to respond to frequency deviations, as requested.

Group

Group

Duke Energy
Greg Rowland
Duke Energy
No
The definition reads as if the FRM is the median of all of the observations reported by the Balancing Authorities and Frequency Response Sharing Groups. Duke Energy would suggest that the definition read, "The median of all of the Frequency Response observations reported annually by a Frequency Response Sharing Group, or Balancing Authority if not a participant in a Frequency Response Sharing Group, for frequency events specified by the ERO. The Frequency Response Measure is calculated as MW/O.1Hz."
No
As a Balancing Authority may not be the entity maintaining or supplying resources, but would be responsible for utilizing applicable resources within its BA Area, Duke Energy would suggest the following definition, "A group whose members consist of two or more Balancing Authorities that collectively utilize operating resources required to achieve a group FRM equal to or more negative than the sum of the Frequency Response Obligations of its members."
No
Duke Energy agrees with allowing single-BA Interconnections to utilize a variable Frequency Bias Setting (FBS). Duke Energy disagrees with NERC allowing Balancing Authorities in a multiple-BA Interconnection to change the ACE and bounds by which the Balancing Authorities are measured under BAL-001 and BAL-002 by operating to a variable FBS. It is desired that a Balancing Authority be capable of recognizing the amount of primary response available in real-time operation, such information can be included among other information in the generation control algorithm; however, the obligation to support the Interconnection frequency under the secondary control standards, and the amount provided for any given frequency, should be based on the same criteria across all Balancing Authorities of the same size. Nathan Cohn in his comments on Union Electric's use of a variable FBS expressed similar concern regarding the equitable sharing of the obligation to support Interconnection frequency in a multiple-BA Interconnection. Take for example two Balancing Authorities with equal total generation and load, but one operating under a fixed FBS and the other operating under a variable FBS. To the extent that a Balancing Authority is not providing Frequency Response comparable to its fixed Frequency Bias Setting, its ACE will reflect the difference to be covered with secondary control and the Balancing Authority will be measured in a manner similar to other BAs of its "size" based upon the FBS. To the extent that the other BA using a variable FBS is not providing Frequency Response comparable to what it would be allocated using a fixed FBS, its ACE will not reflect the difference or any further obligation to support Interconnection frequency at that time with secondary control. Duke Energy's concern regarding non-comparable treatment of all BAs is further amplified by the lack of scrutiny placed on the BA algorithm used to determine the real-time variable FBS, to ensure that compliance cannot be gamed by such use.
No
As indicated in our comments in the past, Duke Energy is certain that as the Interconnection Frequency Bias Setting (FBS) is set closer to the actual Frequency Response in a multi-BA Interconnection, most BAs will be challenged in meeting CPS2, while CPS1 and the proposed Balancing Authority ACE Limit (BAAL) will be more achievable bounds, and in some cases CPS1 performance will improve. Though probably most of the BAs may welcome a FBS set as high in magnitude as allowed to address the potential compliance risk, there are some which may desire to set their FBS closer to their required minimum allocation rather than have to take on a larger obligation in frequency support under the secondary control measures. Duke Energy believes that this proposed standard should incent BAs to provide more than their share of Frequency Response to the Interconnection and allow that good performance to be recognized; however the requirements described in Attachment A for determining the minimum Frequency Bias Setting (FBS), which requires that the FBS be set no lower in magnitude than the FRM, will leave certain over-performing BAs with no choice but to reduce their actual Frequency Response (still well-above their FRO) if they want to operate with a FBS set closer to the Interconnection Minimum allocation and be relieved of the associated increased obligation for frequency support under the secondary control measures. The FBS is embedded within the secondary control measures of CPS1, CPS2 and the draft Balancing Authority

ACE Limit (BAAL). Comparable treatment of similarly-sized BAs (based upon the FRO allocation) is only possible if all BAs are provided the same minimum FBS requirement. To the extent that a BA provides more than its share of response to events, its over-performance will only be recognized if its ACE is allowed to reflect a FBS comparable to its peers, allowing its over-performance to be reflected in ACE in support of bringing frequency closer to 60 Hz. Generation control algorithms implemented today to optimize CPS1 will allow non-zero ACE when in support Interconnection frequency within bounds determined by the BA – there should be no concern of “response withdrawal” with such algorithms in place, the BA will simply get credit for such performance. As depicted in the current document, the over-performing BA would be required to set its minimum FBS at its FRM (or greater in magnitude), taking away what should be considered over-performance, erasing it in ACE, and turning it into an obligation under the secondary control measures. Based upon the draft, the only way that the BA could be treated comparably to other similarly sized BAs held only to operating to the Interconnection Minimum allocation, would be to reduce its actual response in FRM to a value less in magnitude than its Interconnection Minimum allocation. Duke Energy believes that BAs should be incented to provide more than their share of Frequency Response, and be given the opportunity to report performance on a basis comparable to similar-sized BAs. Our opinion is that Attachment A ensures that the Interconnection Frequency Bias Setting will remain at some margin above the actual Interconnection Frequency Response in magnitude – the reliability of the Interconnection will not be at risk by allowing over-performing BAs to operate and report performance on a comparable basis to other similarly-sized BAs based upon the Interconnection Minimum allocation if they choose to do so – to that extent, Duke Energy suggests that the language on page 3 be changed to: “A BA using a fixed Frequency Bias Setting may set its Frequency Bias Setting to any number the BA chooses up to 125% of its Frequency Response Measure as calculated on FRS Form 1, but no less in magnitude than its Interconnection Minimum allocation as determined by the ERO.” Regarding the argument which could be offered that a larger FBS in magnitude will also allow wider bounds for control performance, Duke Energy agrees that a large portion of the BA operation will be around 60 Hz where such a benefit could be realized, however it would also come at the cost of a larger obligation than other comparably-sized BAs in sustained support of frequency during the more critical times of significant deviation from 60 Hz where the BA’s compliance could be at risk. Below 59.95 Hz in the Eastern Interconnection (the Frequency Trigger Limit under BAAL), the additional MWs needed to be compliant for any given frequency are greater than the MWs of imbalance allowed by the larger BAAL bound – comparably-sized BAs will not be comparably judged if the standard forces over-performing BAs to assume a larger FBS (in magnitude) than their peers – that should be the decision of the BA. We believe that the proposed language above will create the proper incentive for a Balancing Authority to provide more than its minimum allocation of Frequency Response, and allow it to choose if it wants to make that performance part of a larger FBS (in magnitude), knowing the associated risks and benefits of that decision. Duke Energy supports this standard allowing for Frequency Response Sharing Groups, however the requirements and supporting documents need to clearly allow the FRSG to be treated no differently than if it was a Balancing Authority and shield the participating BAs from compliance scrutiny when all scrutiny should be placed on the FRSG performance as a whole. At the top of Page 3, the standard attachment allows the FRSG to “calculate a group NIA and measure the group response to all events in the reporting year on a single FRS Form 1”, however at the bottom of page 3, the standard attachment still requires the FRSG BAs to individually fill out Form 1 and Form 2 for the purposes of determining the minimum Frequency Bias Setting. Duke Energy believes that the standard language in Attachment A, and the supporting form(s), should allow the FRSG, if it chooses, to also report the split of the group FRM which the BAs will use to individually determine their Frequency Bias Setting, rather than require each BA in an FRSG to still maintain Form 1 and Form 2 data. Form 1 could be modified for the FRSG to report the group’s FRM along with the split of the FRM among the members, and another form could be developed for each FRSG BA to fill out, replicating only the section of Form 1 (column S) where each BA could provide values for its FRM allocation, its desired FBS, its minimum FBS allocation, and so on.

No

Duke Energy agrees with allowing the ERO to perform this function, however the industry needs some assurance that this Procedure cannot be changed outside of the Standards Process for approval by the industry. In the sixth line of the third paragraph on page 5, the statement should reference Table 2. Page 5 reads as if the BAs will submit their data based upon Form 1 which includes an adjustment to the Interconnection peak load (initially 0.9), and then the ERO will determine whether the Interconnection minimum FBS is still more than 20% above the measured response – if so, the

minimum FBS will be adjusted, requiring the BAs to reassess their new minimum FBS based upon a different factor, and decide whether to use that value or choose a value up to 125% of their FRM, resulting in another iteration of values being submitted to the ERO. If the ERO is going to do an independent assessment of Interconnection Frequency Response to the events, on an annual basis prior to gathering data from the BAs, the ERO could compare the total FBS being used by the BAs against the estimated Frequency Response over that period to determine if an adjustment is warranted, and then the ERO could include the appropriate adjustment factor (0.9, 0.8, etc..) in Form 1 for the BAs to use. If the ERO is not going to estimate the Frequency Response aside from the BAs, multiple iterations will be likely. Duke Energy suggests the following language to cover the point above: "On an annual basis, the ERO will review the Interconnection total minimum Frequency Bias Setting for the prior period and compare it against the Interconnection's total natural Frequency Response determined for that period. If an Interconnection's total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection's total natural Frequency Response by more (in absolute value) than 0.2 percentage points of the Interconnection non-coincident peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of Interconnection non-coincident peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response. The ERO will include the adjustment factor in the Interconnection Form 1 used by the Balancing Authorities for the calculation of the new minimum Frequency Bias Setting. The Form 1 information from the Balancing Authorities will be gathered by the ERO in coordination with the regions of each Interconnection to determine the final Interconnection Frequency Bias Setting for the next period."

No

Similar to our earlier concern, the industry needs some assurance that the calculation of the Interconnection FRO described in the report cannot be changed outside of the Standards Process for approval by the industry. Duke Energy does not support using a 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the result is an allocation which can be supported. To the extent that the standard drafting team moves in the direction of using 59.7 Hz as the basis for the FRO, then it needs to follow a methodology similar to the other Interconnections for determining the credible multiple contingency to cover.

Yes

Though Duke Energy does not agree with some of the points in the Background Document, it does justify the rationale used by the SDT. Additional comments: at the top of page 23, it states that the basic Frequency Response Obligation is based on non-coincident peak load and generation data reported in FERC Form 714, however the actual calculation is missing and should be based upon the reported MWh, not the peak load as stated. At the bottom of page 23, it states that Attachment A proposes the three options for event criteria, however doesn't clarify why it was chosen that the Eastern Interconnection would be held to the largest event over the last 10 years, while others will be based upon the largest category C loss-of-resource (N-2) event.

No

Given the FERC deadline approaching for NERC to deliver a Frequency Response standard, Duke Energy supports the adoption of this standard with some reservations. We believe that the proposed standard addresses the FERC directive to NERC, however it also introduces some longer-term issues related to secondary control and related costs that may have not been anticipated by the FERC. To that point, Duke Energy believes that if this standard is adopted, the industry will have the time and opportunity through the NERC standards development process to mitigate some of the concerns presented in our comments."

The concern raised in Duke Energy's comments in item 4 will not be a factor for a few years, but will be an issue as more and more BAs are in the position of their FRM being better than the Interconnection Minimum allocation. We believe that the language that we proposed for calculating the minimum FBS in a multiple-BA Interconnection allows for the proper incentives for BAs to maintain FRM much better than required, and allows for comparable measurement of secondary control performance between similarly-sized BAs, while presenting no risk to reliability.

Individual

Don Schmit

Nebraska Public Power District
Agree
MRO NSRF [Midwest Reliability Organization - NERC Standards Review Forum]
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
ACES Power Marketing
Yes
We believe that refinements to the definition were needed.
No
We agree that a definition is needed and thank the drafting team for writing one. However, we believe additional refinement of the definition is necessary. Although the definition appears to be written to parallel the Reserve Sharing Group definition, we think the definition needs to be simplified. For one, it encompasses actions that are not necessary. For instance, the proposed definition includes the action to "maintain operating resources". This could literally include generating plant maintenance. We do not agree that a Frequency Response Sharing Group would jointly perform maintenance on their plants. In fact, since the definition applies to BAs, it is entirely possible within the functional model that the BAs do not even own the plants and could not perform joint maintenance. We assume the purpose of including "maintain" was to recognize that maintenance of generating resources would need to be coordinated to ensure that there was sufficient frequency response reserve. We do not believe this needs to be explicitly identified in the definition. Furthermore, we find the use of "operating resource" as a source of potential confusion. While we understand operating resource is intended to mean a facility that provides the ability to increase or decrease MW output based on the frequency deviation, resource has various meanings throughout the standards and its use here could be confusing and contradictory. For instance, TOP-006-2 R1 discusses transmission resources. Furthermore, if an "operating resource" is capable of increasing or decreasing MW output based on frequency deviation, what is a "resource"? In other words, why is "operating" added to the term "resource"? We think it is best to avoid use of the term operating resource and, thus, recommend changing the definition to: "A group of two or more Balancing Authorities that share frequency response reserves and are required to jointly meet the Frequency Response Obligations of its members."
Yes
No
(1) Frequency Response Obligation (FRO) is used inconsistently with the proposed definition in the document. The document uses the term "Interconnection Frequency Response Obligation" in many locations. However, FRO specifically is defined as the BA's "share of the required Frequency Response". It does not apply to the Interconnection. How can the Interconnection have a share of the required frequency response? A new term may need to be defined for the Interconnection required Frequency Response. (2) On page 3 Attachment A states the ERO will post the Frequency Bias Setting for each BA along with their Frequency Response Obligation. Later on the same page, the document states that the BA shall set its Frequency Bias Setting to 100% to 125% of its Frequency Response Measure or Interconnection Minimum. What is the purpose of the ERO determining Frequency Bias Settings if the settings are not going to be used by the BA? What are we missing in the explanation? (3) Late on page 3, the document states that BAs are encouraged to notify NERC if load or generation is transferred. Section 4(a) on page 8 of the Rules of Procedure Appendix 5A – Organization Registration and Certification Manual indicates that changes to a Registered Entity's footprint actually triggers a potential certification audit. Since BAs are required to be certified and moving generation or load from the metered boundaries of one BA to another BA would represent a change in footprint, we suggest removing the word "encouraged" and stating affirmatively that BAs must notify NERC of such changes and referencing the appropriate section of the Rules of Procedure. Otherwise, BAs may not realize notification is actually required.
Yes

Overall, we agree. However, we suggest the document clarify that the ERO shall perform these tasks in coordination with the Resources Subcommittee. It consists of industry experts that can be an extra resource to NERC. Furthermore, NERC staff working with the Resources Subcommittee will provide additional transparency to the process.

Yes

We agree that this method will provide sufficient frequency response. However, we believe Interconnection Frequency Response Obligation is used inconsistently with the definition of Frequency Response Obligation as documented in our response to other comments.

No

(1) The formula for calculating Frequency Response Obligation appears to be missing on page 23. (2) We are confused by the varying sample rates for the different scan rates in the Definitions of Frequency Values for Frequency Response Calculation table on page 13. It would appear that the time range of values for the average B value varies more than necessary by scan rate. For example, for 2-second scan rates, sampling would start at 20 seconds and end at 52 seconds. However, for the 4-second scan rates, sampling starts at 24 seconds and ends at 48 seconds. Why would it not also cover 20 and 52 seconds for a 4-second scan rate?

No

(1) We believe that the drafting team work has demonstrated that the standard is unnecessary. The data presented in the posting shows that all of the interconnections easily exceed the required Frequency Response necessary to avoid actuating UFLS relays. Since one of the main purposes of the standard is to provide sufficient Frequency Response, it would seem the purpose is already met without implementing and enforceable standard. So why is a standard needed to compel required Frequency Response if it is already provided? (2) Even though we believe the supporting data for the posting demonstrates the standard is unnecessary, we understand NERC is required by a FERC directive to provide a standard. Given this requirement, we do believe the drafting team has largely provided a reasonable standard and supporting documents that only require a few additional adjustments (see our comments in other questions for these adjustments) to finalize the standard. As a result, we will likely end up supporting the standard once these final adjustments are made.

(1) Please strike "that is a member of a multiple BA Interconnection" in R2 and R3. The language makes the requirements difficult to read. We understand this is trying to clarify that these requirements should not apply to BAs such as ERCOT since changing its Frequency Bias Setting does not need to be coordinated with other BAs among other issues, and we do not have an issue with this intent. However, there is an easier way to address this issue without creating a confusing requirement. The SDT should include seeking a variance for the ERCOT area in conjunction with developing the standard. (2) Please strike "in order to represent the Frequency Bias Setting for the combined Balancing Authority Area" in Requirement R4 as it is superfluous and incorrect. First, the two bullets provide the necessary information making the statement unnecessary. Second, the BA Areas are not combined into a single BA Area as implied with the statement "combined Balancing Authority Area". They are still in fact two distinct BA Areas. (3) The data retention period for R1, R2, R3, and R4 is not consistent with the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The data retention section states that data shall be kept for the current calendar year plus the three previous calendar years. This could be up to four years which exceeds the BA audit period of three years. It is unnecessary for a BA to maintain evidence that was already verified in a prior audit. We recommend changing the evidence retention period to three years. (4) Has the drafting team coordinated the addition of the Frequency Response Sharing Group (FRSG) with the Functional Model Working Group and the NERC staff responsible for organizational registration? If not, please do so as NERC will need to be willing to register entities as a FRSG if it is to be utilized. Furthermore, the Functional Model Working Group should document the purpose and intent of the FRSG. (5) We disagree with the VSLs for R1. The VSLs are structured such that a BA's or FRSG's violation is dependent upon the rest of the interconnection to determine the severity level of the violation. If the BAs collectively fail to achieve the Interconnection Frequency Response obligation, a 2% violation of the Frequency Response Measure jumps from a Lower VSL to a High VSL. This should never be the case. No violation by a registered entity should become potentially more or less severe based on the violation of another entity. We encourage the drafting team to work with NERC Legal department in reviewing this VSL further as FERC has already allowed ISO/RTO violations investigation to draw in

third parties that potentially contributed to the ISO/RTO violation to ensure the appropriate party is fined. The principal is similar here in ensuring the appropriate BA is fined for its violation not the violations/failures of other BAs. The background document mentions on page 31 that the motivation for structuring the VSL in this manner was to prevent BAs in multiple BA interconnections from being sanctioned disproportionately. We appreciate the drafting team considering this issue but believe there is a simpler solution. Four VSLs could simply be written based on the percentage the BA misses its own Frequency Response Obligation. Furthermore, the compliance enforcement process already considers if the violation impacted reliability when assessing a sanction. (6) The Frequency Response Obligation (FRO) term is used inconsistently with the definition in the VSLs for R1. The first part of each BA implies that the Interconnection has an FRO. However, the definition specifically states that FRO is the BA's "share of the required Frequency Response". It does not apply to the Interconnection. How can the Interconnection have a share of the required frequency response? A new term may need to be defined for the Interconnection. (7) The implementation plan still references Requirement R5. There is no such requirement. (8) Requirement R1 is not consistent with the recent direction NERC has taken to refocus on reliability and looking forward during compliance audits rather than backwards. For instance, NERC has proposed monitoring internal controls of registered entities because this will provide a reasonable assurance that the registered entity is prepared to comply in the future. Current compliance audits focus mostly on past performance and provide no indication of future reliability. How does Requirement R1 support this forward looking vision when it is a lagging indicator that looks at historical performance? (9) Requirement R4 appears to be inconsistent with Requirement R1 and Attachment A. On page 3, Attachment A states the BA shall set its Frequency Bias Setting to 100% to 125% of its Frequency Response Measure or Interconnection Minimum. However, Requirement R4 states that the BA providing Overlap Regulation Service shall set its Frequency Bias Setting to the sum of its Frequency Bias Settings on FRS Form 1 and FRS Form 2 of its own BA and the BA to which it provides Overlap Regulation Service. For simplicity let's call the BA providing Overlap Regulation Service BA X and the BA receiving the service BA Y. Why would the BA X not set its Frequency Bias Setting to 100% to 125% of the sum of BA X's and BA Y's Frequency Response Measure? This would make Requirement R4 parallel with R2. (10) We do not understand the difference between the two bullets in Requirement R4. They appear to say essentially the same thing and the background document provides no discussion to distinguish their differences. Please provide further explanation.

Group

SERC OC Standards Review Group

Gerry Beckerle

Ameren

No

The definition reads as if the FRM is the median of all of the observations reported by the Balancing Authorities and Frequency Response Sharing Groups. We agree with the Duke Energy suggestion that the definition read, "The median of all of the Frequency Response observations reported annually by a Frequency Response Sharing Group, or Balancing Authority if not a participant in a Frequency Response Sharing Group, for frequency events specified by the ERO. The Frequency Response Measure is calculated as MW/0.1Hz."

No

A Balancing Authority may not be the entity maintaining or supplying resources, but would be responsible for utilizing applicable resources within its BA Area. We would modify the Duke Energy suggestion to read as follows: "A group whose members consist of two or more Balancing Authorities that collectively utilize operating resources with a goal to achieve a group FRM equal to or more negative than the sum of the Frequency Response Obligations of its members."

No

It is important for NERC to monitor the interaction between the deployment of this standard and its impact on CPS1, CPS2, and BAAL. If performance in the CPS criteria is degraded, there should be a halt in the reduction of the minimum bias setting allowed. There is also concern that we are providing the correct incentives to the entities to provide the appropriate amount of frequency response. We also suggest that clarification be made so that changes in the BA's footprint that would necessitate

changes in the bias setting or the FRO be permanent changes, not just temporary. It is unclear how performance would be measured for a BA versus a frequency response sharing group.

No

We believe the industry needs some assurance that the calculation of the interconnection FRO cannot be changed without rigorous review and input from the industry. In addition the clarification should be made how the one in ten year loss for the Eastern Interconnection (4500 MW) would change after 10 years. Would the same methodology be used or would the largest Category C (n-2) be used?

Yes

We agree with the Duke Energy comments on this question.

The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Individual

Brett Holland

Kansas City Power & Light

Yes

Yes

Yes

No

The Standard proposes a calculation that overstates the frequency response obligation (FRO) for Balancing Authorities.

No

Criteria 3 - Why are frequency thresholds different between regions when generator governor reaction is supposed to be the same between regions? Criteria 5 - What is the reasoning that multiple events that are not stabilized within 18 seconds not being considered? Criteria 6 - How are "changes in scheduled interchange" or load change determined in regions with interconnections with multiple BAs with different time zones?

Yes

Yes

No

The Standard does not consider instances for smaller BAs that operate generation for peak conditions and acquire energy for most of the operating year.

Individual

Angela P Gaines

Portland General Electric Company

The issue with proposed Reliability Standard BAL-003-1, requirement R1, is that the Annual Frequency Response Measure (FRM) is determined after the fact with an entity unable to identify or monitor compliance (on non-compliance) along the way. Also, the requirement seems to go the opposite direction of NERC's risk based initiatives where collecting historic compliance information become unsustainable.
Individual
Kathleen Goodman
ISO New England Inc.
Agree
Last submitted comments of ISO-NE which have not been addressed and, for efficiency sake, do not believe we should be requested to re-submit.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Standards Review Group
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Agree
Entergy is in agreement with comments submitted by SERC on 11/5/0212.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery, NERC Reliability Compliance Coordinator
Associated Electric Cooperative, Inc. - NCR01177
Agree
SERC OC Standards Review Group
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes
Yes
No
If a BA is using a frequency bias setting and is not providing Overlap Regulation Service (supplying actual interchange, frequency response, and schedules to another BA), then we can assume it is supplying regulation service. Was the intent of the requirement to simply state that all BA's must have a bias setting less than zero at all times? Please clarify the intent of this requirement.
No
(1) This document lacks definitions of terms such as CCadj, DFcc, DFcbr, resource contingency criteria (in the attachment, this is called the "target contingency criteria"), etc. (2) Of value to entities would be a sample calculation. (3) "The largest category C (N-2) event is used for all interconnections except the Eastern which uses the largest event in the last 10 years". Why aren't all interconnections using the same design contingency design basis? (4) The NERC 2012 CPS2 bounds has an Eastern Interconnection frequency bias of -6,360 MW/.1Hz. Can the DT explain why this attachment refers to an Interconnection frequency response obligation of -1,002MW/.1Hz. This is a significant difference.

No
While the discussion of primary frequency response includes inertial energy, the term inertial energy is missing from the definition of "primary frequency response".
No
The purpose of BAL-003 was to calculate frequency bias in the ACE equation used in BAL-001. The Standard is currently confusing to understand and it is unclear how the bias is calculated. It is recommended that efforts should be made to clarify the changes, especially Attachment A.
The VSL's refer to the FRM (Frequency Response Measure). If that is the intent of the Standard, then GO's and GOP's should be included in the applicability since they are the entities responding to the AGC signals. If the intent is the FRO (Frequency Response Obligation) only, then the VSL's should be updated.
Individual
David Jendras
Ameren
Yes
Yes
The word "jointly" may add confusion and we believe it is unnecessary.
Yes
No
We disagree on having different methodologies for determining the targets, and would like clarity added for when those targets may change, such as what will happen after the largest event in the last 10 years rolls off the books for the EI?
Yes
Yes
Yes
While we support this draft, we believe that this might only be a starting point and as additional knowledge and experience is gained through the implementation of this standard and other efforts such as the FRI, that the improvements can be embraced by all parties, even if those improvements result in relaxed requirements.
Individual
Maggy Powell
Exelon Corporation and its affiliates
Yes
Please see response to question 8. The FRM definition is acceptable within the context of the attachment description; however, without clarifying the terms under which the ERO specifies which events are to be measured, the FRM definition is too variable.
Yes
No
Please see response to question 8.

No

Exelon is troubled by the approach of having requirements that rely so heavily on the attachment to the standard. The use of both of the documents is required to be compliant and this makes it difficult to determine what the obligations are and increases the chance for error in interpretation. The suggested changes below in response to question 8 take information from the Attachment and establish requirements so that an entity does not have to go back and forth between the two documents to identify its obligations. Attachment A should then be modified to include examples of Forms 1 and 2 and instructions for completing the form for Balancing Authorities and Frequency Response Sharing Groups.

No

Please see response to question 8.

No

Exelon checked "no" because it does not support the current draft standard. Exelon's position is that efforts to modify frequency monitoring and control should be directed at the existing standards. Since Frequency Bias is already a component of ACE, and ACE performance is tracked by both CPS 1 and CPS 2, it seems evident that NERC already has in place mechanisms for evaluating frequency response. NERC already has in place mechanisms for ensuring sustained frequency response during a contingency, through the Disturbance Control Standard (DCS) and its requirement for the contingent Balancing Authority to deploy resources. Under the current BAL-003-0.1b language, Balancing Authorities are given a consistent means for determining frequency bias, via the minimum requirement of 1% peak generation or 1% peak load. Together with the above references to existing CPS 1 performance measurements, current standards meet the objectives outlined in BAL-003-1. This proposed draft BAL-003-1 complicates the setting of Frequency Bias and attempts to go beyond that purpose into frequency response performance, without clear rules for how to perform. Exelon is also concerned with moving this standard forward while there is an ongoing field trial that could impact whether this standard should be put into place. For example, waivers are in place for CPS 2 for participating Balancing Authorities and there is ongoing effort with the BAAL field trial set of standards that will establish performance metrics around frequency control. As an alternate approach to waiting to move forward on the standard, Exelon recommends the following BAL-003-1 Requirement language: R1. The ERO shall identify up to five [5] system frequency events in each Interconnection that will be included in the Form 1 and 2 data requests for Balancing Authorities by April 30th each year. R2. Each Balancing Authority shall submit the following data to the ERO annually by July 15: R2.1 The total annual net output of generating plants inside the Balancing Authority Area. R2.2 The total annual load with losses inside the Balancing Authority Area. R3. Each Balancing Authority shall calculate its Frequency Response Measure using Forms 1 and 2 as posted by the ERO. (See Attachment A_Form 1 and Form 2) R4. Each Balancing Authority or Frequency Response Sharing Group shall submit Forms 1 and 2 to contacts designated by the ERO before the expiration of ERO established deadlines, which shall be no earlier than 30 days after posting of Forms 1 and 2. R5. The ERO shall post the following information: R5.1. Each Interconnection's Frequency Response Obligation R5.2 Each Balancing Authorities Frequency Response Obligation R5.3 Each Balancing Authorities Frequency Bias Setting R6. Each Balancing Authority shall implement in its ACE equation its ERO established Frequency Bias Setting during the ERO established three-day implementation period. No further adjustments can be implemented outside of the parameters established below in the upcoming year unless a Balancing Authority coordinates with the Regional Entity and the affected Balancing Authorities. R6.1 A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value): R6.1.1. The number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1. R6.1.2. The Balancing Authorities share of the Interconnection Minimum as determined by the ERO. R6.2 A Balancing Authority using a variable Frequency Bias Setting shall maintain a setting that is: R6.2.1 Less than zero at all times, and R6.2.2 Equal to or greater in magnitude than its Frequency Response Obligations when Frequency varies from 60 Hz by more than +/-0.036 Hz. R7. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a FRSG shall monitor its Frequency Response Obligation and work with generating facilities or demand response resources to provide sufficient Frequency Response to meet the Frequency Response Obligation assigned by the ERO. R8. Each Balancing Authority that adds or removes generation or load, including through the

use of dynamic transfers, shall notify the ERO to ensure that any needed adjustments to the Interconnection Frequency Response Obligation or Balancing Authority Frequency Response Obligation and Bias can be calculated. R8.1. The ERO shall notify all affected Balancing Authorities of modifications to the Frequency Response Obligation due to the addition or removal of generation or load. R9. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent of the sum of the Frequency Bias Setting as communicated by the ERO for the participating Balancing Authorities.

Individual

Janelle Marriott Gill

Tri-State Generation and Transmission Assn., Inc.

No

It is our opinion that there has not been enough justification to merit creating a new standard. If additional justification is provided then frequency responsive reserves should be a subset of spinning reserves much like spinning reserves are a subset of operating reserves.

We are concerned with the tariff implications associated with this standard. Will this standard create the need for an additional ancillary service under the FERC pro forma OATT?

Individual

Denise M Lietz

Puget Sound Energy

In reviewing the Consideration of Comments document, it is clear that the standard drafting team does not wish for the administrative elements of Attachment A to become items addressed during compliance evaluations ("There is no intent to require filing on a certain date and to have the BA prove to the auditor that a filing was made on that date." This quote appears at several places in the Consideration of Comments documents, but first at page 113). However, because Attachment A is referenced in the standard, its provisions, including the timing table, are all mandatory and enforceable. This result is emphasized by the language of requirement R1, which states that entities "...shall achieve an annual Frequency Response Measure (FRM) as calculated and reported in accordance with Attachment A...." This language means that a failure to file a document on a date specified in the attachment would be a potential compliance violation. Because Attachment A is mandatory and enforceable, the standard drafting team should carefully review its provisions and clarify which elements are requirements and which elements are background statements or guidance. In addition, the use of additional headings and section numbers would add in clarifying the document (for example, at the top of page 3, there is a discussion of how an FRSG would calculate its FRM; however, there is an entire section beginning on page 4 addressing FRM where that discussion should instead appear).

No
See comment in response to question 4 above for a discussion of Attachment A concerns. Appendix 1 of the Frequency Response Standard Background Document contains a discussion about why the use of net actual interchange to calculate an entity's Frequency Response Measure might introduce inaccuracies into that calculation. That discussion ends with the following statement: "The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error." Based on these statements, it is very difficult to support the standard's approach to calculating the Frequency Response Measure. At Puget Sound Energy (PSE), though, we believe that there is another factor to add to the "operational cacophony" listed in Appendix 1. PSE is a comparatively small BA with limited internal generation. We are embedded between two of the largest energy exporters in the Western Interconnection and, when there is a frequency event, their response flows through PSE's system. As a result, PSE will experience transmission losses associated with the two BAs' frequency response as it flows through our system. When PSE's frequency response is measured using net actual interchange, these losses obscure, at least in part, our system's frequency response. As a result, we ask the standard drafting team to consider specifying a process that would allow us to propose and use an equivalent measure of frequency response. For example, while we understand the concerns and difficulties associated with measuring frequency response at the generator as the default measure for all BAs, in our case, a choice to use that measurement option might prove to be a more-feasible way to comply with the standard.
The definition of "Frequency Response Obligation" applies only to a Balancing Authority. However, requirement R1 applies to both FRSGs and BAs and includes a Frequency Response Obligation that applies to each of those entities. As a result, the definition must also address an FRSG's Frequency Response Obligation. The acronym for Balancing Authority is not included following the first reference to the term in requirement R1 (looks like an inadvertent deletion). Requirement R1 states that an entity "... shall achieve an annual Frequency Response Measure (FRM)...." However, the definition of Frequency Response Measure already includes the concept of annual. As a result, the word "annual" should be removed from the requirement. Requirement R1 includes the language "... to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation." This language is a purpose statement rather than a requirement applicable to a FRSG or a BA and should be excluded from the requirement. So long as an FRSG or BA achieves the FRM calculated in accordance with Attachment A, it has done everything necessary to comply with the standard. There are discrepancies between the implementation plan and the proposed standard: - The definitions of "Frequency Response Measure" and "Frequency Response Obligation" in the Implementation Plan are different from those proposed in the draft standard. - The Implementation Plan references "Reserve Sharing Group" rather than "Frequency Response Sharing Group". - The Implementation Plan does not include a definition for the term "Frequency Response Sharing Group". - The Implementation Plan continues to reference R5 in the discussion of the standard's proposed effective date. The annual process dates listed on page 32 of the Background document appear to be inconsistent with those listed in Attachment A.
Individual
Rich Salgo
NV Energy
Yes
Yes
Yes
Yes
This document is improved, and satisfactorily addresses comments from the prior posting.
Yes

Yes
Yes
No
While I support the concept of a Frequency Response Standard with minimum performance obligations, this Standard places the entire obligation for performance on the Balancing Authority (and Frequency Reserve Sharing Group). Requirements R2-R4 are properly assigned to the BA, as this is the entity that is responsible for the configuration and parameters in the ACE equation, including the provision of a frequency bias setting. Requirement 1, however, is a performance requirement over which the BA in the Functional Model has virtually no control or ability to influence. Only a Generator Owner or Generator Operator is in a position of control over the performance under this requirement through the operational control and configuration of the responding generating units. In most BA's, the host BA entity also owns a fair amount, even a vast majority in many cases, of the generation within the BA. However, even in the event that the host BA owned 100% of the generation within its metered boundary, it is the action of the entity exercising its GO/GOP function that impacts the frequency response performance within the Balancing Area. Assignment of R1 to the BA is inappropriate from the standpoint that reliability requirements are to be assigned to the Reliability Functions who are capable of causing compliance to occur. A BA has limited ability to influence the outcome of the R1 performance metric. This is unlike other BA-assigned requirements, such as those related to DCS or CPS compliance. For those, the BA does have considerable influence regarding the curtailment of transactions to restore ACE, the direction of plant loading so as to distribute operating reserve, etc. In contrast, performance under this proposed R1 of BAL-003-1 is dependent upon the actions of the GO/GOP in such things as governor settings, generator control system configuration and other operational or maintenance activities conducted at the generating plant site. For this reason, it is inappropriate to assign this performance requirement to the BA. Rather, the requirements should be allocated among the GO/GOP's of the on-line generation in some fashion. In further support of this notion, refer to the NERC Functional Model, where it is provided that one of the tasks for Generator Operation is to support Interconnection frequency.
Individual
John Tolo
Tucson Electric Power
Yes
however, the number of observations to be used in calculating an entity's FRM is not clear.
Yes
Yes
N/A
Yes
No
I think it should be more clear or better defined that an interconnection does have some input into what events are selected.
No
I believe that the frequency bias obligation of the Western Interconnection is understated.
Yes
No
I feel that a BA's frequency bias for the upcoming year should not be related to present performance.

A BA may have a good response one year and not good response another year and therefore the threshold keeps moving around. I feel it should be related to BA size and therefore somewhat standardized. E.g. a high-performing Balancing Authority will have its frequency bias increased each year due to higher response during the events chosen by the ERO. Conversely, a low-performing Balancing Authority will have its frequency bias reduced each year due to lower response during the events chosen by the ERO.

This is an important task and the efforts of the drafting team are appreciated.

Group

Avista

Scott Kinney

Avista Corp

Agree

Bonneville Power Administration

Individual

Ken Gardner

AESO

[Empty rows]

1. The AESO disagrees with using a non-authoritative background document that has definitions/description of terms used in the reliability standard. It is the opinion of the AESO that these definitions/descriptions need to be authoritative. 2. The AESO has previously submitted comments to the SDT that for the purpose of the FRM calculation, BAs should be able to exclude or include events based on specific conditions or consideration, such as data quality or event suitability (e.g. BA separation from the Interconnection). The revisions made by the SDT do not enable the inclusion of other relevant events in the FRM calculation by a BA. The AESO would like to see these type of events to be permitted in the FRM calculation by a BA.

Individual

Patricia Robertson

BC Hydro

Yes

Additionally, there should be language to clarify that this is a negative value (the same should apply to the definitions of FRO and Frequency Bias). It is fairly obvious that these values should be negative when reading elsewhere in the proposed Standard and its related document but not in their definitions.

Yes

Additionally, there should be language to clarify that the BAs must belong to the same Interconnections to form the FRSG

Yes

BC Hydro applauds the STD's efforts to recognize a more suitable bound for Variable Frequency Bias settings

No

BC Hydro agrees with the principles outlined in the Attachment A but has some concerns as follows: 1.Attachment A is no longer recognized as one of the associated document of the proposed Standard

in its currently posted version. We believe this was removed by mistake. 2. There is no clarity as to how certain factors used in determining the Interconnection FRO such as CCADJ, CBR and BC'ADJ were determined. There is no apparent provision to re-assess any potential changes to these factors over the future years. If such provision is needed or has been provided then consideration should be given to averaging the adjustment over a longer duration (i.e., using the average of the factor observed over a number of years rather than just the year being assessed). 3. The method used for the allocation of the Interconnection FRO to BAs seems to not recognize the fact that frequency response from Load is much less than frequency response from Generation of an equal MW size. 4. If this Attachment A is considered an integral part of the standard then there should be some enforceable measures to ensure applicable entities adhering to the prescribed time line.

No

BC Hydro agrees in principle that the ERO should perform these tasks related to BAL-003-1 but has the following concerns: 1. There is no clear indication whether the Interconnection FRO will be calculated every year, and if yes, how each of the factors involved will be determined. 2. It is not clear whether data gathered in these procedures are only for the determination of annual FRO and FBS, or also to determine whether the BA or the FRSG was in compliance to BAL-003-1 for the assessed year. Since the ERO in this Document seems to be the NERC Resources Subcommittee and its Frequency Work Group, we think this fact should be made clear. The Background document should also be reviewed to ensure its alignment in this regard.

No Comment

Yes

BC Hydro respectfully submits these additional comments/observations: 1. The proposed standard seems to indicate that it is applicable to the identified responsible entities at all times. There might be circumstances where a BA that belongs to a multiple-BA Interconnection became isolated and has to operate in restorative mode which might require adjusting the frequency bias to a value less negative than the minimum FBS setting value in order to follow the much reduced load/generation level in the area. We suggest adding some language in either the Applicability section or in individual Requirements to recognize these circumstances. 2. Effective Dates: the proposed standard specifies a fixed period (12-month or 24-month) following Regulatory Approval which may fall in the middle of the year while the calculation and implementation are performed on an annual basis. Does this represent any conflicts? 3. The proposed standard does not clearly specify whether a BA must choose between using fixed bias or variable bias for the entire year. Should BAs be allowed to switch back and forth between the two methods? If yes, more details may be needed to account for the FRM and minimum FBS. 4. The proposed standard does not clearly specify whether a BA can be part of a FRSG for only part of the year or must be the whole year. 5. The definition of FRO, FRM, FBS, etc. should all include language to indicate the "negative" nature of the value. 6. Measure M2 should have "and uses a fixed bias" added for clarity purpose. 7. In the Additional Compliance Information section of the proposed standard the following info still exists: For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable. Since all reference to AGC Modes have been removed from the Requirements, this additional info should also be removed.

Individual

Gregory Campoli

New York Independent System Operator

Yes

Yes

With a new process we are concerned that the interconnection minimum will initially move from 1.0% to 0.9%.

Yes
No
The drafting team should consider some method for discounting outliers, that may not be explainable.
No
In general we support the work of the DT, and the proposal to measure the systems response to frequency events, along with the method to determine the FRO. My outstanding concern is with enforcement on an entity that does not own the resources that provides the frequency response or the lack of obligation for the entity with the information to provide to the BA to make the assessment of expected frequency response. BA's should at a minimum be given assurance that resources will provide data that BA's could use to forecast frequency response and take corrective actions.
Individual
Robert Blohm
Keen Resources Asia Ltd.
Yes
Yes
Yes
Yes
No
As a professionally trained published statistical expert never compensated by any balloting participant, I consider event selection criterion 7 to be unacceptable because it violates the fundamental statistical procedure of sampling statistical data "as is" and not pre-selecting the data (to fit some preferred even-distribution over time) and therefore biasing it before applying any statistical procedure to the data. Event criterion 6 is also unacceptable for being an an "ad hoc" explicit exclusion, from the definition of the frequency response being measured, of response to frequency events that occur during a specific kind of scheduled generation and load changes. Said exclusion needs to be written into the definition of the Frequency Response that is being measured. It is procedurally improper and unacceptable to bias the sampling procedure by explicit exclusion of data as an alternative to redefining the thing being sampled. In that case it's not generic Frequency Response that is being sampled, but some specific Frequency-Response-less-Response-to-Excluded-Events that is being measured. It is non-transparent and subterfuge to avoid instead accordingy reworking/narrowing the definition of Frequency Response, especially as said reworking requires a clear technical justification that is absent from this standard, and modifying the existing NERC Glossary definition of Frequency Response which Criterion 6 therefore stands in flat violation of.
No
This question is falsely worded. The SDT is specifically NOT using the method detailed in the Frequency Response Initiative Report dated September 30, 2012. So the term "this method" is practically meaningless in this question because it is not clear if it means "the SDT's method" or "the FRI's method". The Background Document specifically states on page 29: "The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered."

What needs to be changed, besides properly wording this question? The FRI method of linear regression should be adopted, and the SDT method of median should be rejected, in the standard to change the first sentence of this question into a true statement from a false statement and to, in answer to the question, provide for the proper amount of Frequency Response.

No

See reply to Question 6. Also, the Background Document is seriously deficient in the discussion of inertial response and therefore how imbalances "cause" frequency deviation. The Background Document is overflowing in discussion of how frequency deviation causes frequency response. In other words, the Background Document is "reactive" and not "proactive". The Background Document lacks any discussion of the internal dynamics of rotating machines, beginning with any definition of what Inertial Response is. Inertial Response is the instantaneous power produced by the lag ("inertia") in the ability of the generator's rotor to slow down to the frequency of the magnetic field in the generator's fixed stator whose frequency is instantaneously lowered by a change in phase angle between voltage and current that is due to a sudden loss of interconnected generation to meet load. Adjustments by voltage response within milliseconds and near the location of the loss are sometimes possible to avert rapid spread of a loss to the frequency of the entire interconnection, and constitute the ongoing work of the Phasor Project long ago initiated by the DOE in the persistent absence of NERC interest or work in this area. NERC and drafting team members under advisement by NERC staff studiously resisted so much as any mention of frequency deviation causation in discussions or in the Background Document. An inexplicable technical Cold War and Berlin Wall built in the 1970s and today separating the DOE Phasor Project from NERC Frequency Response standard development and NERC's so-called Frequency Response "Initiative" needs to be ended and torn down. My document <http://www.robertblohm.com/Inertia.doc> provides missing technical support and explanation for graphs 1-7 on pages 4-10 of the Background Document, on the basis of an exact understanding of Inertial Response.

A probabilistic/statistical basis needs to be developed for the FRM that assesses for usage of frequency response (causation of frequency error) and not just for provision of it. This would also overcome NERC's singular focus on reaction, and NERC's color-blindness to proaction, pointed out in my reply to question 7.

Group

SPP Standards REview Group

Robert Rhodes

Southwest Power Pool

Yes

Yes

Yes

Yes

Delete the 2nd 'that' in the 2nd bullet at the top of page 3.

Yes

Yes

Yes

We like the document and feel that it provides a primer on the frequency response standard. The following are typos in and suggested corrections to the document: -The blue lines referenced in the paragraph under Figure 2 on page 14 are green (A) and red (B). -Insert an 'a' in the 3rd line of the 2nd paragraph in the Sustained Response section on page 19 between 'provides' and 'greater'. -Insert a 'for' in the 2nd line of the 1st paragraph on page 21 between 'resource' and 'all'. -Change 'provide'

to 'provided' in the 3rd line from the bottom line of the 1st paragraph in the Single Event Frequency Response Data section on page 24. -Change the 'east' to 'Eastern Interconnection' in the 4th line of the 1st paragraph in the Median as the Standard's Measure of Balancing Authority Performance section on page 27. -Delete the 'put' in the 3rd bullet on page 29. Also, replace the 'put' in the 5th bullet with 'gave'.

We support the standard as proposed.

Additional typos: Change the ')' to a '(' in the 4th line of M1 of the standard. No further comment

Individual

Marie Knox

MISO

Yes

Yes

No

We agree with the general obligation but believe that the requirement should apply to single BA Interconnections as well. This is supposed to be a North American standard. What other standards shouldn't apply to a single BA Interconnection? We have the same concern with Requirement 2.

Yes

Yes

The first hyperlink on page 3 of the Procedure for ERO Support does not work.

Yes

Yes

Yes

Group

JEA

Thomas McElhinney

JEA

R1 places the burden for compliance on the BA but the BA does not control generation assets and should not be solely responsible for maintaining frequency response. While the standard can still define the amount of Frequency Response for each BA, there needs to be an obligation on the GO/GOP to provide that service as directed by the BA and they should also be held accountable for compliance. Finally, we do not believe that a sufficient study has been conducted to determine the impact of this standard. We are concerned that a substantial number of compliance issues could result and that the resulting cost to maintain compliance could be excessive and we suggest it be put

through the Cost Effective Analysis Process (CEAP). We suggest that the proposed values be evaluated on a sample size within each region to determine the number of compliance issues and for those issues that are found determine what the BA would have to do be compliant.

Individual

Tony Kroskey

Brazos Electric Power Cooperative, Inc.

Agree

ACES Power Marketing

Individual

Mauricio Guardado

Los Angeles Department of Water and Power

Spinning reserves are intended to support the interconnection response to the loss of a resource. If BAL-003-1 is adopted through this Project, the LADWP recommends that the spinning reserve requirements of BAL-002-0.1b and BAL-STD-002-0 be removed, as the Spinning reserve requirement would require utilities to reserve resources in excess of the reserves required in BAL-003-1. LADWP recognizes that this recommendation may be handled through a separate NERC Project, but wanted to submit this comment to bring light to this potential conflict in Reliability Standards.